OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **January 29, 2007**

TO: Dawson Lasseter, P.E., Chief Engineer, Air Quality Division

THROUGH: David Schutz, P.E., New Source Permit Section

THROUGH: Phil Martin, P.E., New Source Permit Section

THROUGH: Peer Review

FROM: Grover R. Campbell, P.E., Existing Source Permit Section

SUBJECT: Evaluation of Permit Application No. **97-058-C (M-2) (PSD)**
Western Farmers Electric Cooperative
Hugo Generating Station
Addition of New 750 MW Boiler (Hugo Unit 2)
SE/4 Section 21, T6S, R19E
Choctaw County
Directions: Approximately three miles west of Ft. Towson on US-70 and 12 miles east of Hugo
Latitude 34.010º, Longitude -95.320º

SECTION I. INTRODUCTION

Western Farmers Electric Cooperative (WFEC) submitted an application for a construction permit on August 29, 2005. WFEC proposes an expansion to their existing Hugo Generating Station (SIC Code 4911). The expansion will include the installation of a 7,125 MMBtu/hr supercritical pulverized coal (SCPC)-fired boiler with a steam turbine generator producing a nominal total of 750 MW. Since the existing facility has emissions in excess of Prevention of Significant Deterioration (PSD) threshold levels (100 TPY) and the modification will add emissions above PSD levels of significance to an existing PSD-major facility, the application has been determined to require full PSD review. Full PSD review consists of the following:

A. Determination of Best Available Control Technology (BACT)
B. Evaluation of existing air quality and determination of monitoring requirements
C. Analysis of compliance with National Ambient Air Quality Standards (NAAQS)
D. Evaluation of PSD increment consumption
E. Evaluation of source-related impacts on growth, soils, vegetation, and visibility
F. Evaluation of Class I area impacts

The Hugo Generating Station was constructed in 1978 under Permit No. PSD-OK-053, is currently operated under Permit No. 97-058-TV issued April 1, 2004, and is subject to Acid Rain Permit No. 2004-190-ARR.

SECTION II. FACILITY DESCRIPTION

The existing coal-fired complex at the Hugo Generating Station consists of one main boiler unit (HU-Unit1) and an auxiliary boiler unit (HU-Aux). This permit will authorize installation of a second coal-fired boiler (designated "HU-Unit2") and associated equipment, all of which is referred to as "Hugo Unit 2." Both HU-Unit1 and HU-Unit2 will primarily combust sub-bituminous coal. HU-Aux is used as backup during turnaround periods and is fueled exclusively with No. 2 fuel oil.

HU-Unit2 will utilize SCPC technology to generate steam to power a 750 MW steam turbine generator. HU-Unit2 will provide baseload power to the electric grid on a continual basis. Depending on energy requirements, HU-Unit2 will operate at full load for the majority of its operating hours although the unit will also be capable of partial load operation. Combustion controls (*i.e.,* low-NO_X burners) and Selective Catalytic Reduction (SCR) will be used to control NO_X emissions associated with the HU-Unit2. To minimize emissions of SO_2 from HU-Unit2, a wet Flue Gas Desulfurization (FGD) system will be installed that uses limestone as the reagent. A fabric filter will be used to control PM_{10} emissions from HU-Unit2. The wet FGD system will be used for the control of acid gases in conjunction with the inherent control afforded by the capture of acid gases on particulates that are removed in the fabric filter. The fabric filter will also control other inorganic hazardous air pollutants (HAP) (metals). The fabric filter combined with the wet FGD system will control emissions of sulfuric acid mist (H_2SO_4 mist). Good combustion control will be utilized to control CO and VOC. The controls selected for the control of SO_2 and particulate also provide a co-benefit of partial control of mercury and other HAP.

The coal handling system for Hugo Unit 2 will utilize both existing and new equipment. Coal is brought to the facility by railcar. The incoming coal will be distributed to the boilers by a coal handling system that includes unloading, active and long-term coal storage, coal reclaim operations, and coal crushing. This permit will authorize the installation of the following coal handling equipment:

- Coal Silo B,
- Emergency Chain Reclaimer,
- Hugo Unit 2 Coal Silos, and
- New Coal Conveyors.

As part of this permit, a bottom ash submerged chain conveyor (SCC) will be installed beneath the furnace outlet on HU-Unit2. The SCC will be designed to continuously remove bottom ash, pyrites, and economizer ash from HU-Unit2. A new dedicated ash sluicing system will transport the ash from the SCC to the existing permitted bottom ash ponds for disposal. There are no emission points associated with the bottom ash process.

This permit includes the addition of a fly ash silo, fly ash storage building, and fly ash rail loadout silo to the existing fly ash system. Dry fly ash will be removed ahead of the scrubber by the fabric filter, and will be either sold for beneficial use or disposed of in permitted onsite storage areas. Fly ash will be pneumatically conveyed to either the Hugo Unit 2 fly ash storage silo or to the existing fly ash storage silo using a new dedicated fly ash conveying system (however, Unit 2 fly ash will not be mixed with Unit 1 fly ash). From both the new and existing fly ash silos, fly ash will be loaded in trucks for off-site sales or landfill disposal, transported to the existing fly ash ponds for wet disposal, or transported to a new fly ash rail loadout silo for off-site sales.

Based on current demand, it is likely all fly ash produced at the facility can be sold for beneficial re-use. For this reason, a new flat storage building will be installed to store fly ash during the off-season (winter) months so that the ash can be reclaimed and sold during the normal construction season.

Limestone and gypsum handling systems will be installed as part of this permit. Limestone will be delivered to the facility via truck. The limestone will be unloaded into a receiving hopper. From the receiving hopper, limestone will be conveyed via a stackout conveyor to a lowering well where it will be discharged onto a limestone pile. Limestone will be reclaimed from the pile via a reclaim tunnel and conveyed to the limestone silos at the limestone preparation/gypsum dewatering building. From the limestone preparation/gypsum dewatering building, limestone will be transferred to silos. From the silos, the limestone will be transferred inside the limestone preparation building where the limestone will be crushed in a wet ball mill and the product will be stored in a tank. From this tank, the limestone slurry will be pumped to the wet FGD system.

Gypsum is the byproduct produced from the combination of limestone and SO_2 in the exhaust gas in the wet scrubber. The gypsum will be sent from the wet FGD system to the limestone preparation/gypsum dewatering building for dewatering. The gypsum will be sent to one of two vacuum filters. The vacuum filters will dewater the gypsum to approximately 90 percent solids. From the limestone preparation/gypsum dewatering building, the gypsum will be transferred via the gypsum stackout conveyor to the gypsum pile. From the pile, gypsum will be loaded into trucks and taken either off-site to be sold or to the permitted on-site landfill.

One new five-year on-site landfill cell will be constructed as part of the construction associated with Hugo Unit 2. The landfill cell will encompass approximately 293,072 square feet of surface area and will hold approximately 1,500,000 tons of waste material. If fly ash, bottom ash, or gypsum cannot be sold or sent to the ash ponds, the materials will be sent to the landfill cell for disposal.

This permit will also authorize the installation of an emergency diesel generator, a diesel fire water pump, and a wastewater spray dryer, all of which will be fired with No. 2 fuel oil. The emergency diesel generator will support HU-Unit2 in case of a power blackout. The emergency diesel generator will have a maximum output of 1,500 kW. The diesel fire water pump will have a maximum output of 525 hp. The wastewater spray dryer unit will be used to evaporate concentrated brine produced from treated facility wastewater and will be rated at no more than 20 MMBtu/hr.

This permit includes the installation of a new cooling tower. The cooling tower will be added to the facility to remove heat from the steam cycle associated with HU-Unit2. Some particulate matter can become entrained in the plume exiting the cells of the cooling tower, which will be minimized through the use of high efficiency drift eliminators.

The existing auxiliary boiler (HU-Aux) at the facility may be used during start-up operations of HU-Unit1 and HU-Unit2. HU-Aux is actually a backup space heating unit. When HU-Unit1 and HU-Unit2 are down, HU-Aux is available for comfort heating needs. HU-Aux combusts No. 2 fuel oil and minor amounts of used oil which is stored in a 450,000-gallon storage tank. HU-Aux is seldom used since it is only for backup.

Other existing ancillary activities include a 450,000-gallon distillate fuel oil storage tank and cooling towers. The facility cooling towers facilitate cooling of other facility equipment by dissipating waste heat to the atmosphere. The cooling towers will not use chrome-based water treatment chemicals.

SECTION III. EQUIPMENT

Emission units (EUs) have been arranged into Emission Unit Groups (EUGs) in the following outline, which specify the existing and proposed sources.

EUG 1A. Coal-fired Main Boiler (HU-Unit1)

EU and Point ID#	Make	Heat Capacity (MMBtu/hr)	Serial #	Installed Date
HU-Unit1, P-1	Babcock & Wilcox	4,600	RB-575	1978

EUG 1B. Supercritical Coal-fired 750 MW Boiler, 866 MW (gross) (HU-Unit2)

EU and Point ID#	Make/Model	Heat Capacity (MMBtu/hr)	Serial #	Installed Date
HU-Unit2, P-24	Unknown*	7,125	Unknown*	Est. 2007

***** The Make/Model is unknown at this time.

EUG 2. Fuel Oil-fired Auxiliary Boiler (HU-Aux)

EU and Point ID#	Make/Model	Heat Capacity (MMBtu/hr)	Serial #	Installed Date
HU-Aux, P-2	Babcock & Wilcox	184	FM-2754	1978

EUG 3. Coal Handling Activities

EU and Point ID#	Activities	Installed Date
HU-Coal1, P-3A	Rotary Car Dumper – Roof Dust Collector 1A	Est. 2007*
HU-Coal1, P-3B	Rotary Car Dumper – Roof Dust Collector 1B	Est. 2007*
HU-Coal1, P-3C	Rotary Car Dumper – Roof Dust Collector 1C	Est. 2007*
HU-Coal1, P-3D	Rotary Car Dumper – Roof Dust Collector 1D	Est. 2007*
HU-Coal1, P-3E	Rotary Car Dumper – Bottom Dust Collector 2	Est. 2007*
HU-Coal2, P-4A	Transfer House - Dust Collector 3	Est. 2007*
HU-Coal2, P-4B	Coal Silo A – Roof Dust Collector 4	Est. 2007*
HU-Coal7, P-25	Coal Silo B – Roof Dust Collector 4A	Est. 2007
HU-Coal2, P-4C	Coal Silo A – Bottom Dust Collector 5	Est. 2007*
HU-Coal7, P-26	Coal Silo B – Bottom Dust Collector 5A	Est. 2007
HU-Coal3, P-5A	Crusher House – Dust Collector 6	Est. 2007*
HU-Coal3, P-5B	Hugo Unit 1 Coal Silos – Dust Collector 7	Est. 2007*
HU-Coal8, P-27	Hugo Unit 2 Coal Silos – Dust Collector 8	Est. 2007
HU-Coal5, P-7A	Reclaim Hopper No. 1 – aboveground	Est. 2007*
HU-Coal5, P-7B	Reclaim Hopper No. 2 – underground	Est. 2007*
HU-Coal5, P-7C	Reclaim Hopper No. 2 – aboveground	Est. 2007*
HU-Coal5, P-7D	Reclaim Hopper No. 3 – aboveground	Est. 2007*
HU-Coal9, P-28	Chain Reclaim (drop to reclaim hopper)	Est. 2007
HU-Coal9, P-29	Chain Reclaim (drop to conveyor R-1)	Est. 2007

* Modified unit

Nomenclature Modifications to EUG 3: Coal Handling Activities in Permit No. 97-058-TV

EU and Point ID#	Activities	EU ID#	Modified Point ID#	Activities Modification
HU-Coal1, P-3	Railcar Unloading – Rotary dump	HU-Coal1	P-3A	Rotary Car Dumper – Roof Dust Collector 1A
		HU-Coal1	P-3B	Rotary Car Dumper – Roof Dust Collector 1B
		HU-Coal1	P-3C	Rotary Car Dumper – Roof Dust Collector 1C
		HU-Coal1	P-3D	Rotary Car Dumper – Roof Dust Collector 1D
		HU-Coal1	P-3E	Rotary Car Dumper – Bottom Dust Collector 2
HU-Coal2, P-4	Conveying (from Railcar)	HU-Coal2	P-4A	Transfer House - Dust Collector 3
		HU-Coal2	P-4B	Coal Silo A – Roof Dust Collector 4
		HU-Coal2	P-4C	Coal Silo A – Bottom Dust Collector 5

EU and Point ID#	Activities	EU ID#	Modified Point ID#	Activities Modification
HU-Coal3, P-5	Crushing	HU-Coal3	P-5A	Crusher House – Dust Collector 6
		HU-Coal3	P-5B	Hugo Unit 1 Coal Silos – Dust Collector 7
HU-Coal4, P-6	Active Storage Pile – Load in by conveyor	Removed – Storage pile arrangement has been modified and moved to EUG 8		
HU-Coal5, P-7	Active Storage Pile – Load out under pile reclaim	HU-Coal5	P-7A	Reclaim Hopper No. 1 – aboveground
		HU-Coal5	P-7B	Reclaim Hopper No. 2 – underground
		HU-Coal5	P-7C	Reclaim Hopper No. 2 – aboveground
		HU-Coal5	P-7D	Reclaim Hopper No. 3 – aboveground
HU-Coal6, P-8	Inactive Storage Pile – Load in by conveyor	Removed – Storage pile arrangement has been modified and moved to EUG 8		

EUG 4A. Unit 1 Ash Handling Activities

EU and Point ID#	Activities	Installed Date
HU-Ash2, P-14A	Hugo Unit 1 Fly Ash Silo Bin Vent #1	1978
HU-Ash2, P-14B	Hugo Unit 1 Fly Ash Silo Bin Vent #2	1978
HU-Ash3, P-15	Hugo Unit 1 Fly Ash Silo Loading to Trucks	1978

Nomenclature Modifications to EUG 4A: Ash Handling Activities in Permit No. 97-058-TV

EU and Point ID#	Activities	EU ID#	Modified Point ID#	Activities Modification
HU-Ash1, P-13	Truck Loading and Unloading (Bottom Ash and Fly Ash)	Removed – Bottom ash emissions are negligible and HU-Ash3 addresses the fly ash load out.		
HU-Ash2, P-14	Fly Ash Conveying/Storage	HU-Ash2	P-14A	Hugo Unit 1 Fly Ash Silo Bin Vent #1
		HU-Ash2	P-14B	Hugo Unit 1 Fly Ash Silo Bin Vent #2
HU-Ash3, P-15	Fly Ash Silo (Load Out)	HU-Ash3	P-15	Hugo Unit 1 Fly Ash Silo Loading to Trucks
HU-Ash5, P-17	Bottom and Fly Ash-Reclaim	Removed – Emissions are negligible from these sources.		

EUG 4B. Unit 2 Ash Handling Activities

EU and Point ID#	Activities	Installed Date
HU-Ash6, P-30	Hugo Unit 2 Fly Ash Silo Bin Vent #1	Est. 2007
HU-Ash6, P-31	Hugo Unit 2 Fly Ash Silo Bin Vent #2	Est. 2007
HU-Ash7, P-32	Hugo Unit 2 Fly Ash Silo Loading to Trucks	Est. 2007
HU-Ash8, P-33	Fly Ash Storage Building – Dust Collector 1	Est. 2007
HU-Ash8, P-34	Fly Ash Storage Building – Dust Collector 2	Est. 2007
HU-Ash9, P-35	Fly Ash Rail Loadout	Est. 2007
HU-Ash10, P-36	Fly Ash Rail Bin Vent #1	Est. 2007
HU-Ash10, P-37	Fly Ash Rail Bin Vent #2	Est. 2007

EUG 5. Facility Traffic

EU and Point ID#	Activities	Installed Date
HU-PT, P-18	Paved and unpaved roads	Est. 2007*

* Modified unit

EUG 6. Storage Tanks

Point and EU ID#	Capacity (gallons)	Material Stored	Installed Date
HU-T, P-19	450,000	Distillate Fuel Oil	1980
HU-T, P-20	2,030	Unleaded Gasoline	1980
HU-T, P-21	12,000	Diesel	1980

EUG 7A. Unit 1 Emergency Engines

Point and EU ID#	Capacity (hp)	Make/Model	Installed Date
HU-G, P-22	630	Black Start Diesel Generator	1980
HU-G, P-23	285	Cummins Diesel Fire Water Pump	1980

EUG 7B. Unit 2 Emergency Engines

Point and EU ID#	Capacity (hp)	Make/Model	Installed Date
HU-G, P-38	525	Diesel Fire Water Pump*	Est. 2007
HU-G, P-39	2,220	Emergency Diesel Generator*	Est. 2007

***** The Make/Model is unknown at this time.

EUG 8. Storage Pile Activities

EU and Point ID#	Activities	Installed Date
HU-SP1, P-40	North Active Coal Pile (load-in, pile maintenance, and wind erosion)	Est. 2007*
HU-SP2, P-41	South Active Coal Pile (load-in, pile maintenance, and wind erosion)	Est. 2007*
HU-SP3, P-42	North Long Term Coal Storage (wind erosion)	Est. 2007*
HU-SP4, P-43	South Long Term Coal Storage (wind erosion)	Est. 2007*
HU-SP5, P-44	Gypsum Pile (load-in, load-out, pile maintenance and wind erosion)	Est. 2007
HU-SP6, P-45	Limestone Pile (load-in, pile maintenance, and wind erosion)	Est. 2007
HU-SP7, P-46	Landfill (load-in, pile maintenance, and wind erosion)	Est. 2007

* Modified unit

EUG 9. Limestone Handling Activities

EU and Point ID#	Activities	Installed Date
HU-LS1, P-47	Limestone Receiving Hopper	Est. 2007
HU-LS2, P-48	Limestone Reclaim Tunnel	Est. 2007
HU-LS3, P-49	Limestone Silo 1	Est. 2007
HU-LS4, P-50	Limestone Silo 2	Est. 2007

EUG 10. Wastewater Spray Dryer

EU and Point ID#	Capacity (MMBtu/hr)	Make/Model	Installed Date
HU-SD, P-51	20	Wastewater Spray Dryer*	Est. 2007

***** The Make/Model is unknown at this time.

EUG 11A. Unit 1 Cooling Towers

EU and Point ID#	Activities	Installed Date
HU-CT1, P-52	Hugo Unit 1 Cooling Tower	1978
HU-CT1, P-53	Hugo Unit 1 Auxiliary Tower	1978

EUG 11B. Unit 2 Cooling Tower

EU and Point ID#	Activities	Installed Date
HU-CT2, P-54	Hugo Unit 2 Cooling Tower	Est. 2007

SECTION IV. EMISSIONS

Pollutant emissions have been estimated based on the following.

A. New/Modified Units Emission Factors

EU and Point ID#	Description	Pollutant	Emission Factor	Factor Reference
HU-Unit2, P-24	HU-Unit2 (7,125 MMBtu/hr) (430 TPH coal)	NO_X	0.05 lb/MMBtu (Annual)	BACT Limit
			0.07 lb/MMBtu (30-day)	
		CO	0.15 lb/MMBtu	BACT Limit
		VOC	0.0036 lb/MMBtu	BACT Limit
		PM_{10} [A]	0.025 lb/MMBtu	Voluntary Limit
		SO_2	0.065 lb/MMBtu	BACT Limit
		H_2SO_4 Mist	3.7×10^{-3} lb/MMBtu	BACT Limit
		Mercury [B]	8.0×10^{-6} lb/MMBtu	NSPS Subpart Da
HU-Coal1, P-3A	Rotary Car Dumper – Roof Dust Collector 1A (3,000 TPH)	PM_{10}	5.30×10^{-5} lb/ton 98% control	AP-42 (1/95) Section 13.2.4
HU-Coal1, P-3B	Rotary Car Dumper – Roof Dust Collector 1B (3,000 TPH)	PM_{10}	5.30×10^{-5} lb/ton 98% control	AP-42 (1/95) Section 13.2.4
HU-Coal1, P-3C	Rotary Car Dumper – Roof Dust Collector 1C (3,000 TPH)	PM_{10}	5.30×10^{-5} lb/ton 98% control	AP-42 (1/95) Section 13.2.4
HU-Coal1, P-3D	Rotary Car Dumper – Roof Dust Collector 1D (3,000 TPH)	PM_{10}	5.30×10^{-5} lb/ton 98% control	AP-42 (1/95) Section 13.2.4
HU-Coal1, P-3E	Rotary Car Dumper – Bottom Dust Collector 2 (4,200 TPH)	PM_{10}	5.30×10^{-5} lb/ton 98% control	AP-42 (1/95) Section 13.2.4
HU-Coal2, P-4A	Transfer House - Dust Collector 3 (3,000 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-Coal2, P-4B	Coal Silo A – Roof Dust Collector 4 (3,000 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-Coal7, P-25	Coal Silo B – Roof Dust Collector 4A (3,000 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-Coal2, P-4C	Coal Silo A – Bottom Dust Collector 5 (4,800 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2

EU and Point ID#	Description	Pollutant	Emission Factor	Factor Reference
HU-Coal7, P-26	Coal Silo B – Bottom Dust Collector 5A (2,400 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-Coal3, P-5A	Crusher House – Dust Collector 6 (2,400 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-Coal3, P-5B	Hugo Unit 1 Coal Silos – Dust Collector 7 (2,400 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-Coal8, P-27	Hugo Unit 2 Coal Silos – Dust Collector 8 (2,400 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-Coal5, P-7A	Reclaim Hopper No. 1 – aboveground (1,200 TPH)	PM_{10}	5.30×10^{-5} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
HU-Coal5, P-7B	Reclaim Hopper No. 2 – underground (1,200 TPH)	PM_{10}	5.30×10^{-5} lb/ton 75% control	AP-42 (1/95) Section 13.2.4
HU-Coal5, P-7C	Reclaim Hopper No. 2 – aboveground (1,200 TPH)	PM_{10}	5.30×10^{-5} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
HU-Coal5, P-7D	Reclaim Hopper No. 3 – aboveground (2,400 TPH)	PM_{10}	5.30×10^{-5} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
HU-Coal9, P-28	Chain Reclaim (drop to reclaim hopper) (2,400 TPH)	PM_{10}	5.30×10^{-5} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
HU-Coal9, P-29	Chain Reclaim (drop to conveyor R-1) (2,400 TPH)	PM_{10}	5.30×10^{-5} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
HU-Ash6, P-30	Hugo Unit 2 Fly Ash Silo Bin Vent #1 (62.5 TPH)	PM_{10}	4.60×10^{-1} lb/ton 98% control	AP-42 (10/01) Section 11.12.2
HU-Ash6, P-31	Hugo Unit 2 Fly Ash Silo Bin Vent #2 (62.5 TPH)	PM_{10}	4.60×10^{-1} lb/ton 98% control	AP-42 (10/01) Section 11.12.2
HU-Ash7, P-32	Hugo Unit 2 Fly Ash Silo Loading to Trucks (99.8 TPH)	PM_{10}	6.48×10^{-3} lb/ton 90% control	AP-42 (1/95) Section 13.2.4
HU-Ash8, P-33	Fly Ash Storage Building – Dust Collector 1 (62.5 TPH)	PM_{10}	4.60×10^{-1} lb/ton 98% control	AP-42 (10/01) Section 11.12.2

EU and Point ID#	Description	Pollutant	Emission Factor	Factor Reference
HU-Ash8, P-34	Fly Ash Storage Building – Dust Collector 2 (62.5 TPH)	PM_{10}	4.60×10^{-1} lb/ton 98% control	AP-42 (10/01) Section 11.12.2
HU-Ash9, P-35	Fly Ash Rail Loadout (100 TPH)	PM_{10}	6.48×10^{-3} lb/ton 90% control	AP-42 (1/95) Section 13.2.4
HU-Ash10, P-36	Fly Ash Rail Bin Vent #1 (62.5 TPH)	PM_{10}	4.60×10^{-1} lb/ton 98% control	AP-42 (10/01) Section 11.12.2
HU-Ash10, P-37	Fly Ash Rail Bin Vent #2 (62.5 TPH)	PM_{10}	4.60×10^{-1} lb/ton 98% control	AP-42 (10/01) Section 11.12.2
HU-PT, P-18	Paved and unpaved roads	PM_{10}	uncontrolled for paved haul road 50% control for unpaved haul roads	AP-42 (12/03) Section 13.2.1 (paved) Section 13.2.2 (unpaved)
HU-G, P-38	Diesel Fire Water Pump (525 hp)	NO_X	0.031 lb/hp-hr	AP-42 (10/96) Section 3.3
		CO	6.68×10^{-3} lb/hp-hr	AP-42 (10/96) Section 3.3
		VOC	0.0025 lb/hp-hr	AP-42 (10/96) Section 3.3
		PM_{10}	2.2×10^{-3} lb/hp-hr	AP-42 (10/96) Section 3.3
		SO_2	2.05×10^{-3} lb/hp-hr	AP-42 (10/96) Section 3.3
HU-G, P-39	Emergency Diesel Generator (2,220 hp)	NO_X	8.50 g/bhp-hr	Emission Data Sheet
		CO	1.3 g/bhp-hr	Emission Data Sheet
		VOC	0.51 g/bhp-hr	Emission Data Sheet
		PM_{10}	0.35 g/bhp-hr	Emission Data Sheet
		SO_2	2.05×10^{-3} g/bhp-hr	AP-42 (10/96) Section 3.3
HU-SP1, P-40	North Active Coal Pile: Load-in (2,600 TPH)	PM_{10}	5.30×10^{-5} lb/ton 36% control	AP-42 (1/95) Section 13.2.4
	Wind Erosion	PM_{10}	1.02 threshold friction velocity	AP-42 (1/95) Section 13.2.5
	Maintenance Pushed to Reclaim 2	PM_{10}	1.05 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2

EU and Point ID#	Description	Pollutant	Emission Factor	Factor Reference
	Maintenance Pushed to Reclaim 3	PM_{10}	1.05 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2
HU-SP2, P-41	South Active Coal Pile: Load-in (3,000 TPH)	PM_{10}	5.30×10^{-5} lb/ton 36% control	AP-42 (1/95) Section 13.2.4
	Wind Erosion	PM_{10}	1.02 threshold friction velocity	AP-42 (1/95) Section 13.2.5
	Maintenance Pushed to Reclaim 1	PM_{10}	1.05 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2
HU-SP3, P-42	North Long Term Coal Storage Wind Erosion	PM_{10}	1.12 threshold friction velocity	AP-42 (1/95) Section 13.2.5
HU-SP4, P-43	South Long Term Coal Storage Wind Erosion	PM_{10}	1.12 threshold friction velocity	AP-42 (1/95) Section 13.2.5
HU-SP5, P-44	Gypsum Pile: Load-in (18.2 TPH)	PM_{10}	2.58×10^{-4} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
	Truck Load-out (81.25 TPH)	PM_{10}	2.58×10^{-4} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
	Wind Erosion	PM_{10}	0.62 threshold friction velocity	AP-42 (1/95) Section 13.2.5
	Pile Maintenance	PM_{10}	0.24 VMT/hr uncontrolled	AP-42 (12/03) Section 13.2.1
HU-SP6, P-45	Limestone Pile: Stackout Lowering Well (600 TPH)	PM_{10}	0.0003 lb/ton 75% control	AP-42 (1/95) Section 13.2.4
	Wind Erosion	PM_{10}	0.62 threshold friction velocity 50% control (cover)	AP-42 (1/95) Section 13.2.5
	Pile Maintenance	PM_{10}	0.01 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2
HU-SP7, P-46	Landfill: Load-in (71.9 TPH)	PM_{10}	2.58×10^{-4} lb/ton uncontrolled	AP-42 (1/95) Section 13.2.4
	Wind Erosion	PM_{10}	1.02 threshold friction velocity	AP-42 (1/95) Section 13.2.5
	Pile Maintenance (dozer)	PM_{10}	1.82 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2
	Pile Maintenance (compactor)	PM_{10}	1.69 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2
	Pile Maintenance (water truck)	PM_{10}	0.5 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2
	Pile Maintenance (grader)	PM_{10}	4.0 VMT/hr 50% control	AP-42 (12/03) Section 13.2.2

EU and Point ID#	Description	Pollutant	Emission Factor	Factor Reference
HU-LS1, P-47	Limestone Receiving Hopper (600 TPH)	PM_{10}	2.58×10^{-4} lb/ton 98% control	AP-42 (1/95) Section 13.2.4
HU-LS2, P-48	Limestone Reclaim Tunnel (400 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-LS3, P-49	Limestone Silo 1 (400 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-LS4, P-50	Limestone Silo 2 (400 TPH)	PM_{10}	1.10×10^{-3} lb/ton 98% control	AP-42 (8/04) Section 11.19.2
HU-SD, P-51	Wastewater Spray Dryer (20 MMBtu/hr)	NO_X	20 lb/1000 gal	AP-42 (9/98) Section 1.3
		CO	5 lb/1000 gal	AP-42 (9/98) Section 1.3
		VOC	0.2 lb/1000 gal	AP-42 (9/98) Section 1.3
		PM_{10}	1 lb/1000 gal	AP-42 (9/98) Section 1.3
		SO_2	7.10 lb/1000 gal	AP-42 (9/98) Section 1.3
HU-CT2, P-54	Hugo Unit 2 Cooling Tower (563,000 gal/min)	PM_{10}	0.0005% drift efficiency	BACT Limit

A. PM_{10} emission limit is filterable plus condensable PM_{10} emissions. Compliance with NSPS PM_{10} emission limitations is based on filterable PM_{10} emissions only (0.015 lb/MMBtu).

B. Mercury emission factor is based on compliance with the mercury emission limit of 66×10^{-6} lb/MWh for subbituminous coal (wet units) specified in EPA's notice of reconsideration of the Standards of Performance for New and Existing Stationary Sources: Electric Steam Generating Units (the Clean Air Mercury Rule or CAMR); see 70 F.R. 62213, October 28, 2005.

B. Existing Units Emission Factors

EU and Point ID#	Description	Pollutant	Emission Factor	Factor Reference
HU-Unit1, P-1	HU-Unit1 (4,600 MMBtu/hr) (280 TPH coal)	NO_X	Emission Limitation *: 1,670 lb/hr 4,500 TPY	
		CO	12,000 lb/hr	Highest CEM reading plus 20% safety margin
		VOC	0.0075 lb/MMBtu	Stack test
		PM_{10}	0.0136 lb/MMBtu	NSPS "Modification" threshold

EU and Point ID#	Description	Pollutant	Emission Factor	Factor Reference
		SO_2	0.998 lb/MMBtu	NSPS “Modification” threshold
HU-Aux, P-2	HU-Aux (184 MMBtu/hr, 1,314 GPH #2 fuel oil)	NO_X	0.3 lb/MMBtu	Subchapter 33 limit
		CO	7.5 lb/Mgal	AP-42 (7/98), Sect. 1.3 plus 50%
		VOC	0.3 lb/Mgal	AP-42 (7/98), Sect. 1.3 plus 50%
		PM_{10}	0.3 lb/MMBtu	Subchapter 19 limit
		SO_2	0.8 lb/MMBtu	Subchapter 31 limit
HU-Ash2, P-14A	Hugo Unit 1 Fly Ash Silo Bin Vent #1 (62.5 TPH)	PM_{10}	0.46 lb/ton 98% control	AP-42 (10/01) Section 11.12.2
HU-Ash2, P-14B	Hugo Unit 1 Fly Ash Silo Bin Vent #2 (62.5 TPH)	PM_{10}	0.46 lb/ton 98% control	AP-42 (10/01) Section 11.12.2
HU-Ash3, P-15	Hugo Unit 1 Fly Ash Silo Loading to Trucks (62.5 TPH)	PM_{10}	6.48×10^{-3} lb/ton 90% control	AP-42 (1/95) Section 13.2.4
HU-T, P-19 HU-T, P-20 HU-T, P-21	Distillate Fuel Oil Tank Unleaded Gasoline Tank Diesel Tank	VOC	TANKS4.0	TANKS4.0
HU-G, P-22	Black Start Generator (630 hp)	NO_X	0.031 lb/hp-hr	AP-42 (10/96) Section 3.3
		CO	6.68×10^{-3} lb/hp-hr	
		VOC	0.0025 lb/hp-hr	
		PM_{10}	2.2×10^{-3} lb/hp-hr	
		SO_2	2.05×10^{-3} lb/hp-hr	
HU-G, P-23	Fire Water Pump (285 hp)	NO_X	0.031 lb/hp-hr	AP-42 (10/96) Section 3.3
		CO	6.68×10^{-3} lb/hp-hr	
		VOC	0.0025 lb/hp-hr	
		PM_{10}	2.2×10^{-3} lb/hp-hr	
		SO_2	2.05×10^{-3} lb/hp-hr	
HU-CT1, P-52	Hugo Unit 1 Cooling Tower (85,000 gal/min)	PM_{10}	0.05% drift efficiency	Manufacturer’s specifications
HU-CT1, P-53	Hugo Unit 1 Auxiliary Tower (12,000 gal/min)	PM_{10}	0.05% drift efficiency	Manufacturer’s specifications

* The voluntary NO_X emission limits for HU-Unit 1 are not applicable if HU-Unit2 is not constructed.

Annual emission rates for the existing fire water pump and emergency generator (EUG 7A) were calculated based on maximum hours of operation of 500 hours per year for each unit. Annual emission rates for the auxiliary boiler (EUG 2) were calculated using 1,780,000 gallons of fuel per year. Annual emission rates for the new fire water pump and emergency generator (EUG 7B) were calculated based on maximum hours of operation of 52 hours per year for each unit.

C. Criteria Pollutant Potential Emissions

EUG 1A: Coal-fired Main Boiler (HU-Unit1)

EU and Point ID#	NO_X*		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
HU-Unit1, P-1	1,670	4,500	12,000	4,690	34.5	86.0	4,590	16,400	62.5	224

* These NO_X emission limits for HU-Unit1 are not applicable if HU-Unit2 is not constructed. Values are approximated from permit limits of 1,672.6 lb/hr and 4,498.85 TPY.

EUG 1B: Supercritical Coal-fired 750 MW Boiler (HU-Unit2)

EU and Point ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
HU-Unit2, P-24	356	1,560	1,070	4,690	25.7	113	463	2,030	178	780

EUG 2: Fuel Oil-fired Auxiliary Boiler (HU-Aux)

EU and Point ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
HU-Aux, P-2	55.2	37.4	9.9	6.7	0.4	0.3	147	100	55.2	37.4

EUG 3: Coal Handling Activities

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-Coal1, P-3A	Rotary Car Dumper – Roof Dust Collector 1A	3.18×10^{-3}	0.01
HU-Coal1, P-3B	Rotary Car Dumper – Roof Dust Collector 1B	3.18×10^{-3}	0.01
HU-Coal1, P-3C	Rotary Car Dumper – Roof Dust Collector 1C	3.18×10^{-3}	0.01
HU-Coal1, P-3D	Rotary Car Dumper – Roof Dust Collector 1D	3.18×10^{-3}	0.01
HU-Coal1, P-3E	Rotary Car Dumper – Bottom Dust Collector 2	4.45×10^{-3}	0.02
HU-Coal2, P-4A	Transfer House - Dust Collector 3	0.07	0.31
HU-Coal2, P-4B	Coal Silo A – Roof Dust Collector 4	0.07	0.31
HU-Coal7, P-25	Coal Silo B – Roof Dust Collector 4A	0.07	0.31
HU-Coal2, P-4C	Coal Silo A – Bottom Dust Collector 5	0.11	0.48
HU-Coal7, P-26	Coal Silo B – Bottom Dust Collector 5A	0.05	0.22
HU-Coal3, P-5A	Crusher House – Dust Collector 6	0.05	0.22
HU-Coal3, P-5B	Hugo Unit 1 Coal Silos – Dust Collector 7	0.05	0.22
HU-Coal8, P-27	Hugo Unit 2 Coal Silos – Dust Collector 8	0.05	0.22
HU-Coal5, P-7A	Reclaim Hopper No. 1 – aboveground	0.06	0.26
HU-Coal5, P-7B	Reclaim Hopper No. 2 – underground	0.02	0.09

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-Coal5, P-7C	Reclaim Hopper No. 2 – aboveground	0.06	0.26
HU-Coal5, P-7D	Reclaim Hopper No. 3 – aboveground	0.13	0.57
HU-Coal9, P-28	Chain Reclaim (drop to reclaim hopper)	0.13	0.57
HU-Coal9, P-29	Chain Reclaim (drop to conveyor R-1)	0.13	0.57
TOTAL		**1.07**	**4.67**

EUG 4A. Unit 1 Ash Handling Activities

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-Ash2, P-14A	Hugo Unit 1 Fly Ash Silo Bin Vent #1	0.58	2.54
HU-Ash2, P-14B	Hugo Unit 1 Fly Ash Silo Bin Vent #2	0.58	2.54
HU-Ash3, P-15	Hugo Unit 1 Fly Ash Silo Loading to Trucks	0.04	0.18
TOTAL		**1.20**	**5.26**

EUG 4B: Unit 2 Ash Handling Activities

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-Ash6, P-30	Hugo Unit 2 Fly Ash Silo Bin Vent #1	0.58	2.54
HU-Ash6, P-31	Hugo Unit 2 Fly Ash Silo Bin Vent #2	0.58	2.54
HU-Ash7, P-32	Hugo Unit 2 Fly Ash Silo Loading to Trucks	0.06	0.26
HU-Ash8, P-33	Fly Ash Storage Building – Dust Collector 1	0.58	2.54
HU-Ash8, P-34	Fly Ash Storage Building – Dust Collector 2	0.58	2.54
HU-Ash9, P-35	Fly Ash Rail Loadout	0.06	0.26
HU-Ash10, P-36	Fly Ash Rail Bin Vent #1	0.58	2.54
HU-Ash10, P-37	Fly Ash Rail Bin Vent #2	0.58	2.54
TOTAL		**3.60**	**15.76**

EUG 5: Facility Traffic

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-PT, P-18	Paved and unpaved roads	6.4	28

EUG 6. Storage Tanks

EU and Point ID#	Activities	VOC	
		lb/hr	TPY
HU-T, P-19	Distillate Fuel	0.01	0.01
HU-T, P-20	Unleaded Gasoline	0.24	1.04
HU-T, P-21	Diesel Fuel	0.01	0.01
TOTAL		**0.26**	**1.06**

EUG 7A. Unit 1 Emergency Engines

EU and Point ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
HU-G, P-22	19.5	4.88	4.21	1.05	1.58	0.40	1.29	0.32	1.39	0.35
HU-G, P-23	8.84	2.21	1.90	0.48	0.71	0.18	0.58	0.15	0.63	0.16
TOTAL	**28.3**	**7.09**	**6.11**	**1.53**	**2.29**	**0.58**	**1.87**	**0.47**	**2.02**	**0.51**

EUG 7B: Unit 2 Emergency Engines

EU and Point ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
HU-G, P-38	16.2	0.42	3.51	0.09	1.31	0.03	1.08	0.03	1.16	0.03
HU-G, P-39	41.6	1.08	6.36	0.17	2.50	0.07	4.55	0.12	1.71	0.04
TOTAL	**57.8**	**1.50**	**9.87**	**0.26**	**3.81**	**0.10**	**5.63**	**0.15**	**2.87**	**0.07**

EUG 8: Storage Pile Activities

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-SP1, P-40	North Active Coal Pile: Load-in	0.09	0.39
	Wind Erosion	0.03	0.13
	Pile Maintenance Pushed to Reclaim 2	0.86	3.78
	Pile Maintenance Pushed to Reclaim 3	0.86	3.78
HU-SP2, P-41	South Active Coal Pile: Load-in	0.10	0.44
	Wind Erosion	0.03	0.13
	Pile Maintenance Pushed to Reclaim 1	0.86	3.77
HU-SP3, P-42	North Long Term Coal Storage Wind Erosion	0.42	1.84
HU-SP4, P-43	South Long Term Coal Storage Wind Erosion	0.28	1.23
HU-SP5, P-44	Gypsum Pile: Load-in	0.005	0.02
	Truck Load-out	0.02	0.09

EU and Point ID#	Activities	PM10	
		lb/hr	TPY
	Wind Erosion	0.02	0.09
	Pile Maintenance	0.0022	0.01
HU-SP6, P-45	Limestone Pile: Stackout Lowering Well	0.05	0.22
	Wind Erosion	0.02	0.09
	Pile Maintenance	0.01	0.04
HU-SP7, P-46	Landfill: Load-in	0.02	0.09
	Wind Erosion	0.27	1.18
	Pile Maintenance (dozer)	1.10	4.82
	Pile Maintenance (compactor)	1.06	4.64
	Pile Maintenance (water truck)	0.54	2.37
	Pile Maintenance (grader)	1.70	7.45
TOTAL		**8.35**	**36.60**

EUG 9: Limestone Handling Activities

EU and Point ID#	Activities	PM10	
		lb/hr	TPY
HU-LS1, P-47	Limestone Receiving Hopper	0.0031	0.01
HU-LS2, P-48	Limestone Reclaim Tunnel	0.01	0.04
HU-LS3, P-49	Limestone Silo 1	0.01	0.04
HU-LS4, P-50	Limestone Silo 2	0.01	0.04
TOTAL		**0.03**	**0.13**

EUG 10: Wastewater Spray Dryer

EU and Point ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
HU-SD, P-51	2.9	13	0.7	3.1	0.03	0.1	1.0	4.4	0.2	1.0

EUG 11A: Unit 1 Cooling Towers

EU and Point ID#	Activities	PM10	
		lb/hr	TPY
HU-CT1, P-52	Hugo Unit 1 Cooling Tower	31.9	140
HU-CT1, P-53	Hugo Unit 1 Auxiliary Tower	4.5	19.7
TOTAL		**36.4**	**160**

EUG 11B: Unit 2 Cooling Tower

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-CT2, P-54	Hugo Unit 2 Cooling Tower	9.9	43

Total Facility Potential Criteria Emissions

EUG ID	EUG Description	NO_X		CO		VOC		SO_2		PM_{10}	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
EUG 1A	HU-Unit1	1,670	4,500	12,000	4,690	34.5	86.0	4,590	16,400	62.5	224
EUG 1B	HU-Unit2	356	1,560	1,070	4,690	25.7	113	463	2,030	178	780
EUG 2	HU-Aux	55.2	37.4	9.9	6.7	0.4	0.3	147	100	55.2	37.4
EUG 3	Coal Handling	-	-	-	-	-	-	-	-	1.1	4.7
EUG 4A	Unit 1 Ash Handling	-	-	-	-	-	-	-	-	1.2	5.3
EUG 4B	Unit 2 Ash Handling	-	-	-	-	-	-	-	-	3.6	15.8
EUG 5	Facility Traffic	-	-	-	-	-	-	-	-	6.4	28
EUG 6	Tanks	-	-	-	-	0.3	1.1	-	-	-	-
EUG 7A	Unit 1 Emergency Engines	28.3	7.1	6.1	1.5	2.3	0.6	1.9	0.5	2.0	0.5
EUG 7B	Unit 2 Emergency Engines	57.8	1.5	9.9	0.3	3.8	0.1	5.6	0.2	2.9	0.1
EUG 8	Storage Pile	-	-	-	-	-	-	-	-	8.4	36.6
EUG 9	Limestone Handling	-	-	-	-	-	-	-	-	-	0.1
EUG 10	Wastewater Spray Dryer	2.9	13	0.7	3.1	-	0.1	1.0	4.4	0.2	1.0
EUG 11A	Unit 1 Cooling Towers	-	-	-	-	-	-	-	-	36.4	160
EUG 11B	Unit 2 Cooling Tower	-	-	-	-	-	-	-	-	9.9	43
TOTAL		**2,170**	**6,120**	**13,100**	**9,390**	**67.0**	**201**	**5,210**	**18,500**	**368**	**1,340**

D. Hazardous Air Pollutants (HAP) Potential Emissions

Significant amounts of HAP are emitted from the coal-fired main boilers. HAP emissions from other emission units are insignificant. HAP emissions reflecting continuous operation are calculated based on a maximum of 280 TPH coal combustion for HU-Unit1, 430 TPH coal combustion for HU-Unit2, and the emission factors from AP-42 (9/98), Tables 1.1-14, 1.1-15, and 1.1-18. The mercury emissions for HU-Unit2 are based on the Clean Air Mercury Rule (CAMR) mercury emission limit of 66 x 10^{-6} lb/MWh (gross) and the HU-Unit2 gross output of 866 MWh (equivalent to 8.0 x 10^{-6} lb/MMBtu for HU-Unit2). As promulgated, the CAMR specifies a mercury emission limit of 42 x 10^{-6} lb/ MWh; however, on October 28, 2005, the U.S. Environmental Protection Agency (EPA) published notice of its reconsideration of the CAMR and therein proposed a revised mercury emission limit of 66 x 10^{-6} lb/MWh which has been incorporated into this permit. The Oklahoma Department of Environmental Quality (DEQ) is reserving the right to reopen the permit, if necessary, to administratively amend the specified mercury emission limit to incorporate the CAMR emission limit following final action by EPA. Hydrochloric acid and hydrogen fluoride emissions for HU-Unit2 are based on 95 percent removal efficiency.

Potential HAP Emissions from the Main Boilers

Pollutant	CAS#	HU-Unit1 Potential Emissions		HU-Unit2 Potential Emissions		Total Potential Emissions	
		lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Arsenic	7440382	0.115	0.504	0.176	0.771	0.291	**1.28**
Cadmium	7440439	0.014	0.061	0.022	0.096	0.036	**0.157**
Chromium	7440473	0.073	0.320	0.112	0.491	0.185	**0.811**
Mercury	7439976	0.023	0.101	0.057	0.250	0.080	**0.351**
Hydrochloric Acid	7647010	336	1,470	25.8	113	362	**1,580**
Hydrogen Fluoride	7664393	42.0	184	3.23	14.2	45.2	**198**
Nickel	7440020	0.078	0.342	0.120	0.526	0.198	**0.868**
Formaldehyde	50000	0.067	0.293	0.103	0.451	0.170	**0.744**
H_2SO_4 Mist*	-	-	-	26.4	116	26.4	**116**
Lead	7439921	0.118	0.517	0.181	0.793	0.299	**1.31**
Beryllium	7440417	0.006	0.026	0.009	0.040	0.015	**0.066**

* Not a HAP

SECTION V. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

OAC 252:100-8-31 states that BACT "*means an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Director, on a case-by-case basis, taking into account energy, environmental, and economic impacts or other costs, determines is achievable for such source or modification….*"

A BACT analysis is required to assess the appropriate level of control for each new or physically modified emissions unit for each pollutant that exceeds the applicable PSD Significant Emissions Rate (SER). As shown in Table V.I, emissions of NO_X, CO, SO_2, VOC, PM_{10}, and H_2SO_4 mist exceed the applicable SER.

In addition, the applicant determined that HAP emissions of lead, mercury, fluorides, and beryllium also exceed the SER. However, under the NSR Reform rules adopted by DEQ (OAC 252:100-8 Part 7), the definition of "Regulated NSR Pollutant" does not include HAP:

> "(B) Regulated NSR pollutant does not include:
>
> (i) any or all HAP either listed in section 112 of the Act or added to the list pursuant to section 112(b) of the Act, which have not been delisted pursuant to section 112(b) (3) of the Act, unless the listed HAP is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act; or
>
> (ii) any pollutant that is regulated under section 112(r) of the Act, provided that such pollutant is not otherwise regulated under the Act."

Therefore, under PSD regulations, a BACT review for control of HAP emissions is not required. However, since emissions of HCL and fluorides (as HF) exceed major source levels, a BACT analysis is required pursuant to OAC 252:100-8-5(d)(1)(A).

Table V.I PSD Significance Levels

EUG Description	NO_X	CO	SO_2	VOC	PM_{10}	H_2SO_4
EUG 1A. HU-Unit2	1,560	4,690	2,030	113	780	116
EUG 3. Coal-Handling	-	-	-	-	4.7	-
EUG 4B. Ash Handling	-	-	-	-	15.8	-
EUG 7B. Emergency Engines	1.5	0.3	0.2	0.1	0.1	-
EUG 8. Storage Pile Activities	-	-	-	-	36.6	-
EUG 9. Limestone Handling	-	-	-	-	0.1	-
EUG 10. Wastewater Spray Dryer	13	3.1	4.4	0.1	1.0	-
EUG 11B. Cooling Tower Unit	-	-	-	-	43	-
Total Added Emissions	**1,575**	**4,693**	**2,035**	**113**	**881**	**116**
PSD Significance Level	40	100	40	40	15	7
PSD Review Required?	Yes	Yes	Yes	Yes	Yes	Yes

Other pollutants for which PSD significance levels are established (asbestos, vinyl chloride, H_2S, and TRS) are not expected to be emitted in other than negligible amounts from this type of facility.

The U.S. EPA has stated its preference for a “top-down” approach for determining BACT and that is the methodology used for this permit review. After determining whether any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the available control technologies, including the most stringent control technology, for a similar or identical source or source category. If the proposed BACT is equivalent to the most stringent emission limit, no further analysis is necessary.

If the most stringent emission limit is not selected, further analyses are required. Once the most stringent emission control technology has been identified, its technical feasibility must be determined; this leads to the reason for the term “available” in Best Available Control Technology. A technology that is available and is applicable to the source under review is considered technically feasible. A control technology is considered available if it has reached the licensing and commercial sales stage of development. In general, a control option is considered applicable if it has been, or is soon to be, developed on the same or similar source type. If the control technology is feasible, that control is considered to be BACT unless economic, energy, or environmental impacts preclude its use. This process defines the “best” term in Best Available Control Technology. If any of the control technologies are technically infeasible for the emission unit in question, that control technology is eliminated from consideration.

The remaining control technologies are then ranked by effectiveness and evaluated based on energy, environmental, and economic impacts beginning with the most stringent remaining technology. If it can be shown that this level of control should not be selected based on energy, environmental, or economic impacts, then the next most stringent level of control is evaluated. This process continues until the BACT level under consideration cannot be eliminated by any energy, environmental, or economic concerns.

The five basic steps of a top-down BACT review are summarized as follows:

- Step 1. Identify Available Control Technologies
- Step 2. Eliminate Technically Infeasible Options
- Step 3. Rank Remaining Control Technologies by Control Effectiveness
- Step 4. Evaluate Most Effective Controls Based on Energy, Environmental, and Economic impacts
- Step 5. Select BACT and Document the Selection as BACT

In addition, in accordance with EPA guidance, the BACT analysis will address emissions from startup, shutdown, and malfunction as they pertain to the proposed BACT limits.

Technologies and emissions limit data were identified by the applicant and by AQD through a review of EPA’s RACT/BACT/LAER Clearinghouse (RBLC) as well as EPA’s New Source Review (NSR) and Clean Air Technology Center (CATC) websites, recent state BACT determinations for similar facilities, and vendor-supplied information. Another valuable source of information on recently proposed and permitted coal-fired power generation plants is the National Coal-Fired Utility spreadsheet (National spreadsheet) maintained by EPA. The latest edition of this spreadsheet can be accessed on the Internet at http://www.epa.gov/ttn/catc/dir1/natlcoal.xls. Other sources of information include state agency contacts, recent articles, and contacts with vendors to help identify emission rates that have not yet been added to the National spreadsheet or the RBLC. For convenience of discussion and background information for the reader, a summary of the RBLC and National spreadsheet review for the years 2002 to January 2005 is given in Table V.II. The 1999 permit for the Kansas City Power & Light Company's Hawthorne Station was also included as it is the only new (not retrofitted) plant constructed in the U.S. that fires PRB coal and uses Selective Catalytic Reduction (SCR) technology.

Table V.II
RECENT ELECTRIC POWER PLANT PERMITS, BACT DETERMINATIONS, AND CONTROL TECHNOLOGY

State/Permit No./Date	Company/ Facility [3]	Pollutant	BACT, lb/MMBtu [1,2]	Control Technology [16]
Kentucky V-02-001 (rev-3) 4/14/2006 Final Permit	Peabody Energy Thoroughbred Generating Station 2@750 MW (Bit)	NO_X	0.07	LNB, SCR
		SO_2	0.167	WFGD
		CO	0.10	GCC
		VOC	0.0072	GCC
		PM_{10}	0.018 [4]	ESP, WESP
		H_2SO_4	0.00497	ESP, WESP
Texas Draft Permit 5/6/2005 NCFU	City Public Service J.K. Spruce Unit 2 750 MW (PRB)	NO_X	0.07 / 0.05 [7]	LNB, SCR
		SO_2	0.06 [7]	WFGD
		CO	0.15 [7]	GCC
		VOC	0.0025 [4]	GCC
		PM_{10}	0.022 [8]	FF
		H_2SO_4	0.0037 [8]	WFGD, FF
Texas PSD-TX-1039 3/10/05 NCFU & Permit	Sandy Creek Energy Associates, L.P./ LS Power Sandy Creek Energy 800 MW (PRB)	NO_X	0.07 / 0.05 [7]	LNB, SCR
		SO_2	0.12 / 0.10 [7]	DFGD
		CO	0.15 [7]	GCC
		VOC	0.0036 [8]	GCC
		PM_{10}	0.04 [8]	FF
		H_2SO_4	0.0037 [8]	DFGD, FF

State/Permit No./Date	Company/ Facility [3]	Pollutant	BACT, lb/MMBtu [1,2]	Control Technology [16]
Nebraska 58343-P4 3/9/2005 NCFU & Permit	Omaha Public Power District Nebraska City Unit 2 660 MW (Sub)	NO_X	0.07	LNB/SCR
		SO_2	0.095	DFGD
		CO	0.16 [4]	GCC
		VOC	0.0034 [8]	GCC
		PM_{10}	0.018 [8]	FF
		H_2SO_4	0.0042 [8]	DFGD, FF
Louisiana PSD-LA-677 8/22/05 NCFU	NRG Energy, Inc Big Cajun II Generating Station 675 MW (PRB)	NO_X	0.071 [9]	LNG/SCR
		SO_2	0.10 [9]	WFGD
		CO	0.135 [9]	GCC
		VOC	0.0035 [9]	GCC
		PM_{10}	0.018 [9]	ESP
		H_2SO_4	-	-
Colorado 04PB1015 4/5/2005 NCFU & Permit	PSC of Colorado Comanche Generating Station Unit 3 750 MW (PRB)	NO_X	0.08 [10]	LNB, OFA, SCR
		SO_2	0.10 [10]	DFGD
		CO	0.13 [5]	GCC
		VOC	0.0035 [8]	GCC
		PM_{10}	0.013 [8]	FF
		H_2SO_4	0.0042 [8]	-
Nevada AP4911-1349 5/5/2005 NCFU & RBLC	Newmont Mining TS Power Plant 200 MW (?)	NO_X	0.067 [6]	LNB/SCR
		SO_2	0.09 / 0.65 [6,11]	DFGD
		CO	0.15 [6]	GCC
		VOC	-	-
		PM_{10}	0.012 [6]	FF
		H_2SO_4	0.001 [9]	DFGD, FF
Illinois 189808AAB 4/25/2005 Final Permit	Prairie State Generating Company,LLC Prairie State Campus 2@ 50 MW (Bit)	NO_X	0.07	LNB, SCR
		SO_2	0.182	WFGD
		CO	0.12 [6]	GCC
		VOC	0.004 [6]	GCC
		PM_{10}	0.035 [4]	ESP, WESP
		H_2SO_4	0.005 [6]	-
Georgia Draft Permit 11/1/2004 NCFU	Longleaf Energy Associates / LS Power, LLC Longleaf Energy Station 2@600 MW (Bit)	NO_X	0.07 [12]	LNB, OFA, SCR
		SO_2	0.12 [12]	DFGD
		CO	0.15 [12]	GCC
		VOC	0.006 [12]	GCC
		PM_{10}	0.033 [12]	FF
		H_2SO_4	0.005 [12]	DFGD, FF

State/Permit No./Date	Company/ Facility [3]	Pollutant	BACT, lb/MMBtu [1,2]	Control Technology [16]
Missouri 102004-007 10/28/2004 NCFU & Permit	City Utilities of Springfield Southwest Power Station, Unit 2 275 MW (Sub)	NO_X	0.08	LNB, SCR
		SO_2	0.095	DFGD
		CO	0.16	GCC
		VOC	0.0036 [9]	GCC
		PM_{10}	0.018 [9]	FF
		H_2SO_4	-	-
Wisconsin 03-RV-248 10/19/2004 NCFU	Wisconsin Public Service Corporation Weston Plant Unit 4 500 MW (Sub)	NO_X	0.07 / 0.06 [7]	LNB, SCR
		SO_2	0.10 [7] / 0.09	DFGD
		CO	0.15 [6]	GCC
		VOC	0.0036	GCC
		PM_{10}	0.02 [4]	FF
		H_2SO_4	0.005 [6]	DFGD
Utah DAQE-AN0327010-04 10/15/2004 NCFU	Intermountain PSC Intermountain Unit 3 950 MW (Sub)	NO_X	0.07	LNB, SCR
		SO_2	0.10 [6] / 0.09	WFGD
		CO	0.15	GCC
		VOC	0.0027 [9]	GCC
		PM_{10}	0.024 [6]	FF
		H_2SO_4	0.0044 [6]	WFGD, FF
Nebraska 58048 3/20/2004 NCFU & Permit	Hastings Utilities Whelan Energy Center 220 MW (Sub)	NO_X	0.08	LNB, SCR
		SO_2	0.12	SDA
		CO	0.15 [4]	GCC
		VOC	-	-
		PM_{10}	0.018 [4]	FF
		H_2SO_4	-	-
West Virginia R14-0024 3/2/2004 NCFU & Permit	Longview Power, LLC Longview Power 600 MW (Bit)	NO_X	0.08 [6,13]	LNB, SCR
		SO_2	0.15 [4,14]	WFGD
		CO	0.11 [4]	GCC
		VOC	0.004 [4]	GCC
		PM_{10}	0.018 [5]	FF
		H_2SO_4	0.0075 [4]	DSI, FF
Wisconsin 03-RV-166 1/14/2004 NCFU & Permit	Wisconsin Energy Elm Road Generating Station 2@615 MW (Bit)	NO_X	0.07	LNB, GCC, SCR
		SO_2	0.15	WFGD
		CO	0.12 [6]	LNB, GCC
		VOC	0.0035 [6] (LAER)	LNB, GCC
		PM_{10}	0.018 [4]	FF, WESP
		H_2SO_4	0.01 [6]	WFGD, WESP

State/Permit No./Date	Company/ Facility [3]	Pollutant	BACT, lb/MMBtu [1,2]	Control Technology [16]
Arkansas 1995-AOP-RO 8/20/2003 NCRU & Permit	Plum Point Associates, LLC Plum Point Energy 800 MW (Sub)	NO_X	0.09 [6]	LNB, OFA, SCR
		SO_2	0.16 [4]	DFGD
		CO	0.16 [9]	GCC
		VOC	0.02 [9]	GCC
		PM_{10}	0.018 [9]	FF
		H_2SO_4	0.0061 [9]	DFGD, FF
Montana 3182-00 7/21/2003 NCRU & Permit	Bull Mountain Energy Company Roundup Power Project 2@390 MW (Bit)	NO_X	0.07 [6]	LNB, OFA, SCR
		SO_2	0.12 [6]	DFGD
		CO	0.15 [8]	PD&O
		VOC	0.003 [8]	PD&O
		PM_{10}	0.015 [8,15]	FF
		H_2SO_4	0.0064 [9]	DRGD, FF
Iowa 02-528 6/17/2003 NCRU & RBLC	MidAmerican Energy Company MidAmerican Unit 4 790 MW (PRB)	NO_X	0.07	SCR
		SO_2	0.15	DFGD
		CO	0.154 [6]	GCC
		VOC	0.0036 [4]	GCC
		PM_{10}	0.025 [4]	FF
		H_2SO_4	0.0042	DFGD, FF
Kansas 0550087/C-3855 10/8/2002 NCRU	Sand Sage Power, LLC Holcomb Unit 2 660 MW (PRB)	NO_X	0.08	ULNB
		SO_2	0.15	DFGD
		CO	0.15 [4]	GCC
		VOC	0.0035 [4]	GCC
		PM_{10}	0.018 [5]	FF
		H_2SO_4	0.00421	DFGD, FF
Wyoming CT-3030 9/25/2002 NCRU & RBLC	Black Hills Power & Light WYGEN 2 500 MW (PRB)	NO_X	0.07	LNB, SCR
		SO_2	0.1 / 0.15 [4]	Semi-Dry SDA
		CO	0.15 [8]	GCC
		VOC	0.01 [8]	GCC
		PM_{10}	0.012 [9]	FF
		H_2SO_4	-	-
Kansas 888 8/17/1999 NCRU & Permit	Kansas City Power & Light Company Hawthorn Station 570 MW (PRB)	NO_X	0.08 / 0.10 [6]	SCR
		SO_2	0.12 / 0.13 [4]	DFGD
		CO	0.16 [9]	GCC
		VOC	0.0036 [9]	GCC
		PM_{10}	0.018 [9]	FF
		H_2SO_4	-	-

Notes:

1. 30-day rolling average unless noted otherwise.
2. PM_{10} is for filterable and condensable.
3. Bit (bituminous), Sub (subbituminous), PRB (Powder River Basin).
4. 3-hr rolling average or 3-hr block.
5. 6-hr or 8-hr rolling average.
6. 24-hr rolling average or 24-hr block.
7. 12-month rolling average.
8. Annual average or annual per compliance test.
9. Averaging period unknown.
10. Settlement Agreement limitation and considered as BACT.
11. 0.09 and 95% control for sulfur > 0.45%, 0.065 and 91% control for sulfur <0.45%.
12. Proposed limit, not yet specified as BACT.
13. Additional NO_X limitations of 0.07 lb/MMBtu (30-day rolling average) and 0.065 lb/MMBtu (calendar year) were imposed per settlement agreement with citizens group.
14. Additional SO_2 limitations of 0.12 lb/MMBtu (24-hr rolling average) and 0.095 lb/MMBtu (calendar year) were imposed per settlement agreement with citizens group.
15. Limit may drop to 0.012 after 18 months dependent on source test.
16. ACI (activated carbon injection), DFGD (dry flue gas desulfurization), DSI (dry sorbent injection), ESP (electrostatic precipitator), FF (fabric filter–baghouse), GCC (good combustion control or practices), LNB (low NO_X burners), OFA (overfire air), PD&O (proper design and operation), SCR (selective catalytic reduction), SDA (spray dryer absorption), SI (sorbent injection), ULNB (ultra low-NO_X burners), WFGD (wet flue gas desulfurization),

The following proposed and/or permitted projects were excluded from the above list for the reasons stated.

- 7/2005. Kentucky, Louisville Gas and Electric Company-Trimble County Generating Station. Netted out of PSD review for NO_X and SO_2. Proposed NO_X limit is 0.05 lb/MMBtu.
- 12/2004. Rocky Mountain Power-Hardin Generator Project. Only 116 MW and limits are not among lowest.
- 2/2004. Tractebel Power, Inc.-Santee Cooper Cross Generating Station. Netted out of PSD review for NO_X and SO_2. BACT limits for VOC (0.0024 lb/MMBtu) were considered in the Hugo Unit 2 BACT review.
- 2003. New Mexico, Peabody Energy-Mustang Generating Station. BACT issues are unresolved.
- Corn Belt Energy Corporation-Prairie Energy Power Plant. Only 91 MW.
- Tucson Electric Power Company-Springerville Generating Station. Emission limits are not based on BACT.

Table V.III provides a summary of the BACT determinations for the Hugo Unit 2 facility.

Table V.III BACT Summary

Pollutant	BACT Emission Limit lb/MMBtu	Control Technology Description Associated with BACT Emission Limit
HU-Unit2 EGU (SCPC Boiler) Combusting Powder River Basin (PRB) Coal		
NO_X	0.07 [1] / 0.05 [2]	LNB w/OFA and SCR
SO_2	0.065	Wet limestone FGD
PM_{10} Filterable	0.015	Fabric Filter
PM_{10} Total	0.025	Fabric Filter
CO	0.15	Good Combustion Control
VOC	0.0036	Good Combustion Control
H_2SO_4 Mist	5.0×10^{-3}	Wet FGD, Fabric Filter
Material Handling System Emission Points		
PM_{10}	0.01 gr/dscf	Fabric Filter
Cooling Tower		
PM_{10}	0.0005% drift rate	High efficiency drift eliminators
Waste Water (Brine) Spray Dryer		
Combustion Emissions		Low sulfur diesel fuel and good combustion practices
Emergency IC engines		
Combustion Emissions		Low sulfur diesel fuel, good combustion practices, and limited hours of operation

Notes:
1. 30-day rolling average.
2. 12-month rolling average.

A. COAL-FIRED STEAM EGU BOILER (HU-Unit2) BACT

The following sections describe the BACT determination for the proposed HU-Unit2 for each applicable pollutant. It is noted that rapid advancements in emissions control technology for coal-fired boilers have occurred over the last few years, especially in the area of NO_X emissions control. The technologies for control of SO_2, CO, and VOC are much more mature and, therefore, not as much of a “moving target” as for NO_X.

The technology advancement for control of NO_X emissions has been driven primarily by the 1998 NO_X SIP Call and the so-called "Section 126" petitions that followed. These EPA actions have resulted in large reductions in NO_X emissions from power plants in the Eastern U.S. due to the retrofitting of existing coal-fired boilers with both modern combustion technologies and add-on control technologies.

Effort to reduce mercury emissions from coal-fired boilers has been on going since the early 1990s and was brought to the forefront when the EPA issued the proposed MACT rule on January 30, 1994; which, at that time, set the standard for mercury emission limits (20 x 10^{-6} lb/MWh for wet subbituminous units such as Hugo Unit 2). However, the EPA later reversed itself and removed Electrical Generating Units (EGUs) from its list of HAP source categories that must be regulated under Section 112 of the Clean Air Act (CAA). (On May 31, 2006, the EPA reaffirmed this decision). In place of the MACT rule, the EPA promulgated the final Clean Air Mercury Rule (CAMR) on May 18, 2005, which establishes a nationwide cap and trade program based on the mercury reductions it believes are achievable as a co-benefit from control of other pollutants up until the year 2018. On October 28, 2005, the EPA issued notice of its reconsideration of the CAMR and asked for comments. The EPA also revised its proposed mercury emission limits for subbituminous coal (wet units) to 66 x 10^{-6} lb/MWh from the previous CAMR limit of 42 x 10^{-6} lb/MWh.

Per EPA BACT guidelines, proprietary technologies that may be applicable to SCPC fired EGU, including proposed multi-pollutant technologies, have been excluded from this BACT review. Also, per guidance from EPA (December 13, 2005 memo from Stephen D. Page, Director, Office of Air Quality, Planning, and Standards, to Mr. Paul Plath, Senior Partner, E3 Consulting, LLC), an applicant is not required to consider Integrated Gasification Combined Cycle (IGCC) technology in a BACT analysis.

Nitrogen Oxides Emissions

NO_X is the term used to collectively refer to NO and NO_2. NO_X is formed by the oxidation of nitrogen contained in the fuel (fuel NO_X) and when elemental nitrogen and oxygen in the combustion air combine within the high temperature environment of the combustion zone (thermal NO_X). In coal-fired boilers, fuel NO_X generally accounts for approximately 75% of all NO_X generated. Factors affecting the generation of NO_X include flame temperature, residence time, quantity of excess air, and the nitrogen content of the fuel.

Step 1 - Identify All Control Technologies

COMBUSTION TECHNOLOGIES

Low-NO_X Burners (LNB)

LNB are designed to limit NO_X formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, resulting in one or more of the following conditions: (a) reduced oxygen in the primary flame zone; (b) reduced flame temperature; or (c) reduced residence time at peak temperatures. The most recent applications of LNB are called Ultra Low-NO_X Burners due to their improvements over previous LNB technology where advances in control systems, combustion process modifications, and post-combustion carbon burnout technology have further limited NO_X formation.

Overfire Air (OFA)

OFA, also referred to as air staging, is a combustion control technology in which 5% to 20% of the total combustion air is diverted from the burners and injected through ports located above the top burner level. OFA is generally used in conjunction with operating the burners at stoichiometric or slightly sub-stoichiometric conditions, which reduces NO_X formation. The OFA is then added to achieve complete combustion. OFA can be and normally is used in conjunction with LNB.

Good Combustion Control (GCC)

Modern LNB technology generally includes the use of modern combustion control technology and sometimes computerized combustion optimization programs. For this boiler BACT review, LNB technology also means the use of modern combustion control technology, but the label GCC will be used in the BACT review of other combustion pollutants.

Other Combustion Technologies

There are many other combustion technologies that one vendor or another might use to achieve lower NO_X emissions. These include Rotating Opposed Fire Air (ROFA), Natural Gas Reburning (NGR), Fuel Lean Gas Reburning (FLGR), Advanced Gas Reburning (AGR), Amine Enhanced Gas Injection (AEGI), and Induced Flue Gas Recirculation (IFGR, more prominent). However, none of these technologies have been listed as BACT for issued permits, although they may be proposed from a vendor bidding on a particular facility. For this BACT review, these technologies are considered to be part of an overall BACT analysis and no further discussion is necessary.

ADD-ON CONTROLS

Selective Catalytic Reduction (SCR)

SCR is a post-combustion technology in which ammonia is added to the flue gas upstream of a catalyst bed. The ammonia and NO_X react on the surface of the catalyst forming N_2 and water. The NO_X reduction is effective only within a given temperature range, typically 480°F to 800°F. SCR can achieve high reduction efficiencies (70 – 90%) on inlet NO_X concentrations as low as 20 ppm.

Selective Non-Catalytic Reduction

SNCR is a post-combustion technology in which a reagent (ammonia or urea) is injected into the furnace above the combustion zone, where it reacts with NO_X to reduce it to N_2 and water. SNCR reactions occur in the temperature range of 1,600°F to 2,000°F.

Step 2-Eliminate Technically Infeasible Options

SNCR was determined to be technically infeasible for this project. The temperature range for optimum performance of SNCR technology is not compatible with the design and operation of a SCPC EGU.

Step 3- Rank Remaining Control Technologies by Control Effectiveness

Various technical publications and information about the current NO_X emissions reduction technologies were reviewed to determine the range of reported control efficiencies for each of the technically feasible technologies identified in Step 2.

The results of this review indicate that a furnace/combustion control system consisting of LNB with some form of OFA is by far the most commonly applied technology for the control of NO_X emissions and has become a standard component of new utility boiler design. Also, new generation ULNB, typically with OFA and advanced combustion controls, has been applied as retrofit on existing coal-fired boilers to meet NO_X reduction requirements of the NO_X SIP Call, Section 126 Petitions, ozone non-attainment, or other state requirements. Therefore, LNB with OFA represents BACT for coal-fired boiler combustion technology.

Combustion technologies are the most cost effective method of control for reduction of NO_X emissions, but combustion technology alone cannot achieve the BACT emissions levels reached by presently operating and permitted, but not yet constructed, facilities. A review of available performance related data indicates that a modern PRB-fired SCPC boiler equipped with LNB/OFA would be expected to operate with NO_X emission levels from 0.11 to 0.20 lb/MMBtu (with tangential-fired boilers on the lower end and wall-fired boilers on the upper end). The KCP&L Hawthorn Station Unit 5 was designed in 1999 and operates with 0.18 lb/MMBtu firing PRB coal. Numerous coal-fired boilers retrofitted with LNB/OFA are operating at 0.15 lb/MMBtu or below. A year 2000 retrofit of Unit 6 at the W.A. Parish Generating Plant reduced furnace NO_X emissions from 0.4 lb/MMBtu to 0.17 lb/MMBtu. A year 2000 retrofit of the CPS J.K. Spruce Unit 1 with LNB achieved average NO_X emissions of 0.147 lb/MMBtu by 2001 with a reduction to 0.132 lb/MMBtu with installation of a combustion process optimizer program. A year 2002 retrofit of the TMPA Gibbons Creek plant with LNB and advanced combustion controls obtained NO_X emissions averaging 0.11 lb/MMBtu firing PRB coal. A May/June 2002 article by Black & Veatch published in Platt's Power magazine listed eight (8) power plant boilers firing PRB that had been retrofitted with LNB and had emissions ranging from 0.11 lb/MMBtu to 0.15 lb/MMBtu. Based on discussions with the Texas Commission on Environmental Quality (TCEQ), a NO_X emissions rate of 0.15 lb/MMBtu was used as the LNB baseline emissions for the two latest PC-fired units permitted in Texas. On February 27, 2006, the EPA published final amendments to NSPS Subpart Da for coal-fired boilers and established a limit of 1.0 lb/MWh (equivalent to approximately 0.11 lb/MMBtu) for coal-fired boilers. The EPA expects that modern coal-fired boilers with LNB and advanced controls will meet this limitation without add-on SCR.

It is apparent then that the add-on control of SCR is required to obtain BACT levels of emission control below approximately 0.11 lb/MMBtu. Table IV.IV shows the ranking of SCR as add-on control and the NSPS standard baseline of 0.11 lb/MMBtu for LNB/OFA. SCR BACT limits are based on a review of the RBLC, the National spreadsheet, and other published sources.

Table IV.IV NO_X RBLC BACT Emission Limits

Pollutant	Emission Limit (lb/MMBtu)	Control Technology Description Associated with BACT Emission Limit
NO_X	0.07 [1]/ 0.05 [2]	LNB / SCR Permitted – not constructed
	0.07 [1]/ 0.06 [2]	LNB / SCR Permitted – not constructed
	0.067 [3]	LNB / SCR Permitted – not constructed
	0.07 [1]	LNB / SCR Permitted – not constructed
	0.11 [1]	LNB/OFA – NSPS Baseline Limit

1. 30-day rolling average.
2. 12-month rolling average.
3. 24-hr rolling average.

Most permits issued after 2002 and prior to 2005 listed BACT as 0.07 to 0.08 lb/MMBtu on a 30-day rolling average with the exception of the WPSC Weston Plant Unit 4, which included a 0.06 lb/MMBtu 12-month rolling average BACT limit. The recently issued final permit for the Thoroughbred Generating Station has a BACT limit of 0.07 lb/MMBtu. The recently issued construction permits for the CPS J.K. Spruce Unit 2 and the Sandy Creek Energy Plant (both in Texas) have a 0.05 lb/MMBtu 12-month rolling average BACT limit in addition to the 0.07 lb/MMBtu 30-day rolling average. None of these plants have completed construction so they have not demonstrated compliance with the specified permit emission limits over long-term operation.

There is limited operating history of newly constructed units with SCR equipment on PC EGUs firing PRB coal. Kansas City Power & Light's Hawthorn Unit 5 burns PRB coal and is equipped with an SCR system and is meeting 0.08 lb/MMBtu. AQD personnel toured the Hawthorn facility to obtain first hand information on SCR operation. The facility had early problems with catalyst plugging and excessive ammonia slip which caused fouling problems downstream. However, with use of a different catalyst and more experience, the unit meets its 0.08 lb/MMBtu limit. This unit was constructed with space limitations based on the old gas-fired unit space availability; therefore, the design of the inlet duct and mixing grid prior to the SCR catalyst modules could not be optimized. Effective mixing of the flue gas with the ammonia injection is critical to obtaining higher emissions reductions, so AQD does not consider the emission reduction achieved at the Hawthorn Unit 5 as indicative of modern SCR technology.

There have been many existing coal-fired boilers retrofitted with modern LNB and/or SCR in the last few years. A review of EPA Acid Rain data for the 3rd quarter of 2005 showed 29 coal-fired boilers with a NO_X emission rate of 0.05 lb/MMBtu or lower. 11 of those were operating at 0.04 lb/MMBtu to as low as 0.027 lb/MMBtu. This data does not necessarily suggest BACT levels as it is likely that some of these facilities are meeting that NO_X emission level only during the ozone season, which means that the catalyst is not aged as quickly as it would be with continuous operation of the SCR. Also, it may be cost effective for facilities under the NO_X SIP Call or other NO_X emission restrictions to "over control" NO_X emissions at one facility (at relatively high cost) in order to avoid installing add-on technology at another facility. Nonetheless, there is substantial data that demonstrates long-term operation of SCR at emission levels in the range of 0.03 to 0.05 lb/MMBtu. The LG&E Trimble County power plant, which burns a high sulfur coal, was retrofitted with LNB and SCR with a vendor guarantee of 0.032 lb/MMBtu and performance tested at 0.025 lb/MMBtu (that does not represent end of catalyst life efficiency; however, the facility reported 3rd Q 2005 NO_X emissions of 0.03 lb/MMBtu). The AES Somerset Station Unit 1 was the first large coal-fired SCR retrofit installed in the U.S. and was placed in service in June 1999. A later article indicated that the facility had operated successfully for three years at an emissions level of 0.055 lb/MMBtu during ozone seasons, which was a 90% reduction from the baseline level of 0.55 lb/MMBtu. Expert testimony provided for the petitioners in SIERRA CLUB (et al) vs. ENVIRONMENTAL AND PUBLIC PROTECTION CABINET and THOROUGHBRED GENERATING COMPANY, LLC, listed thirteen (13) examples of NO_X emission rates from 0.03 to 0.05 lb/MMBtu, most of which were not BACT requirements (overseas facilities, LAER, non-attainment areas, etc).

Based on the above research and analysis, the top level of control for long term operation of SCR on a boiler firing PRB is considered to be 0.05 lb/MMBtu.

Step 4-Evaluate Most Effective Controls for Energy, Environmental, and Economic Impacts

Step 3 of the BACT evaluation established that SCR in combination with LNB/OFA offers the highest level of NO_X control. In Step 4, the potential energy, environmental, and economic impacts of this control technology are considered.

Energy

No energy cost is assigned to the LNB and OFA. The major area of energy consumption associated with an SCR system is fan power required to overcome the flue gas pressure loss across the catalyst bed. For the proposed unit, SCR will require approximately 0.3 percent of the unit's gross generation. This energy requirement is not considered excessive to preclude the use of SCR.

Environmental

- An SCR system requires large quantities of ammonia for operation.

- Ammonia will also combine with available sulfur compounds and can result in the formation of additional particulate emissions, which in turn adds to the potential for the formation of particulate in the atmosphere that would not be captured by the particulate controls. Also, AQD considers ammonia an air toxic and an ozone precursor. However, these potential negative impacts from ammonia emissions can be reduced somewhat by placing ammonia concentration limits on stack emissions.

- The SCR catalyst is typically classified as a hazardous material and spent catalyst must be treated as hazardous waste.

- The SCR catalyst oxidizes a portion of the SO_2 in the flue gas to SO_3, which can react with moisture in the flue gas to form H_2SO_4. This effect can be minimized with modern SCR catalyst.

- An undesirable consequence of LNB is that reducing NO_X emissions to low levels can increase the amount of CO and VOC emissions. This does not preclude the use of LNB, but may require slightly higher CO and VOC limits than can be achieved for a boiler with higher NO_X emissions.

<u>Economics</u>

The applicant has proposed a BACT limit of 0.05 lb/MMBtu, which is considered the top level of control; therefore, an economic analysis is not necessary.

Step 5-Select BACT and Document the Selection as BACT

The applicant proposed a BACT limit for NO_X emissions of 0.05 lb/MMBtu. Based on the above analysis, this is acceptable to AQD as BACT. The limit will be 0.05 lb/MMBtu based on a 12-month rolling average. The applicant also proposed a shorter term BACT limit of 0.07 lb/MMBtu. This is acceptable to AQD as BACT in order to allow for shorter term variability, especially at end of life catalyst conditions. The short term limit will be 0.07 lb/MMBtu based on a 30-day rolling average. This level of control equals the lowest recently permitted facilities. Control will be accomplished with LNB/OFA and SCR. Compliance will be demonstrated with Continuous Emissions Monitoring System (CEMS) data.

Sulfur Dioxide Emissions

Sulfur dioxide emissions result from the oxidation of the sulfur in the fuel. At the high temperature combustion associated with the boiler, sulfur compounds in the fuel are converted to SO_2 emissions. A small portion of the SO_2 reacts with alkaline products in the ash and approximately 0.2 to 1 percent will form SO_3, a precursor to H_2SO_4 mist. For convenience, and as a worst case scenario, possible SO_2 control technologies were evaluated assuming all the sulfur contained in the fuel is converted to SO_2.

Due to factors including the coal currently being used for Hugo Unit 1, the quality of the coal, the availability of existing rail systems in the vicinity of the facility, and available mine capacity, low sulfur western coal (i.e., PRB coal) was selected as fuel for the Hugo Unit 2 EGU. The coal to be fired in the Hugo Unit 2 boiler over the life of the facility is expected to have an upper average sulfur content limit of approximately 0.7 percent (1.7 lb/MMBtu).

Step 1-Identify All Control Technologies

PRE-COMBUSTION TECHNOLOGIES

Low Sulfur Coal

Since SO_2 is formed from combustion of sulfur contained in the fuel, use of a low sulfur fuel can reduce SO_2 emissions substantially. This is normally done when an existing facility does not have any add-on desulfurization controls as a method to reduce SO_2 emissions.

Coal Washing

Washing coal can remove significant quantities of inorganic elements, including sulfur, by removing ash forming mineral deposits that are embedded in the coal.

ADD-ON CONTROLS

Wet Lime or Limestone Flue Gas Desulfurization (FGD) (Wet Scrubber)

In this system, a reagent is slurried with water and sprayed into the flue gas in an absorber vessel (wet scrubber). The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

A wet FGD can be classified by the reagents used and the by-products generated. The most typical reagents are lime and limestone. Additives, such as magnesium, may be added to the lime or limestone to increase the reactivity of the reagent. The reaction by-products are calcium sulfite and calcium sulfate. The calcium sulfite to calcium sulfate reaction is a result of oxidation, which can be inhibited or forced depending on the desired by-product. The most common wet scrubber application utilizes limestone as the reagent and forced oxidation of the reaction by-products to form calcium sulfate, which can be marketed as synthetic gypsum.

Lime Spray Dryer FGD (Dry Scrubber)

In this system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a dry form upon leaving the system and are subsequently captured in a downstream particulate collection device.

Semi-Dry Lime Spray Dryer (Circulating Dry Scrubber)

In this system, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and SO_2. The by-products leave the absorber in dry form with the flue gas and are subsequently captured in a downstream particulate collection device.

Step 2-Eliminate Technically Infeasible Options

Coal washing has historically been investigated for beneficiation of the fuel through the removal of ash and sulfur prior to the combustion process. Although application of this technology has been used for some eastern bituminous coals, no commercial application of this technology has been successful on PRB coal. Adding moisture content to the coal can significantly reduce the available energy (BTU content and LHV). This is especially true for the sub-bituminous fuels found in the PRB. Both EPRI and DOE have considered the benefits of coal washing, but to date, there are no commercially available “washed” fuels from the PRB fuel suppliers. Therefore, coal washing is not considered a feasible option for PRB coal.

Step 3-Rank Remaining Control Technologies by Control Effectiveness

Table IV.VI ranks SO_2 control technologies based on a typical range of reduction efficiencies and the range of the lowest emission rates identified as BACT in the National Coal Spreadsheet or the RBLC.

Table IV.VI SO_2 RBLC BACT Emission Limits

Control Technology	**Control Efficiency**	**Emission Limit lb/MMBtu**
Wet Limestone FGD	95% to > 98%	0.10 - 0.06
Dry FGD	90% to >95%	0.12 - 0.09
Semi-Dry Lime Spray Dryer	90% - 92%	0.20 - 0.17
Low Sulfur PRB Coal	Baseline	1.7

Step 4-Evaluate Most Effective Controls for Energy, Environmental, and Economic Impacts

The Wygen and Neil Simpson units are indicated in the RBLC as the only units permitted with semi-dry (or circulating dry scrubber) technology with emission rates as low as 0.17 and 0.2 lb/MMBtu that are demonstrated in practice. Since wet FGD and dry FGD have demonstrated lower emission rates, semi-dry technology is not evaluated further.

Wet FGD is a mature technology that is available from a number of suppliers. Wet FGD has the potential to achieve the lowest emissions among the available technologies. Two units operating with the Chiyoda scrubber have successfully operated with efficiencies in the 96 percent removal range but are burning a higher sulfur coal, which requires a higher efficiency. In addition, higher removal efficiency is easier to achieve with higher inlet SO_2 concentrations. Since removal efficiency is based on the inlet amount, strict evaluation of the removal efficiency is not as effective as reviewing the outlet emission rate to evaluate the effect on the environment. The outlet emission rate recognizes the inherent advantage of low sulfur coal in addition to the removal efficiency achieved by the FGD system.

Dry FGD is also an established (demonstrated) technology. Lime spray drying is the most commonly used type of FGD applied to units firing PRB coal, primarily because of lower cost and lower makeup water usage.

Energy

A wet FGD system requires a significant amount of electric energy for operation. For Hugo Unit 2, the power consumption of a wet FGD is estimated to be approximately two percent of the proposed unit's generation capability. This level of energy consumption is significant and must be considered in the BACT determination. A dry FGD system results in less energy consumption. A dry FGD system is assumed to consume approximately 0.7 percent of the unit's generating capacity.

Environmental

A wet FGD system produces a by-product of calcium sulfite or calcium sulfate. However, most new wet FGD systems utilize the limestone forced oxidation (LSFO) system which produces a synthetic gypsum that can be used to produce gypsum products (wallboard, cement retarder, or an agricultural soil amendment). Because the waste product may be beneficially used, this reduces the need for (or size of) a landfill for this project and is a substantial benefit associated with a wet LSFO FGD system for environmental, economic, and aesthetic factors.

In a dry FGD system, the scrubber waste products are collected in the fabric filter along with the fly ash. Mixing the scrubber wastes with the fly ash (as is inherent with a dry FGD system) generally makes the fly ash unsuitable for reuse. Consequently, if a dry FGD system is installed, land filling of the fly ash/scrubber wastes will be required, and will negatively impact environmental, economic, and aesthetic factors.

The wet FGD system requires more energy to operate than a dry FGD system. This has an effect environmentally, because approximately 2 percent additional fuel is required to be burned to produce the same net energy.

Selection of the SO_2 control technology will impact the control of H_2SO_4 mist emissions. The dry scrubber followed by a fabric filter has been demonstrated to provide significantly better H_2SO_4 mist control because the fabric filter for a dry FGD system is positioned downstream from the absorber.

Selection of the SO_2 control technology will also impact the control of mercury emissions. CAMR was promulgated in March 2005 (70 F.R. 28606). On October 28, 2005, EPA published notice of its reconsideration of the CAMR (70 F.R. 62213). Within the notice, EPA determined "[t]he technologies that appeared most effective in reducing mercury emissions were those that were installed, or likely would be installed, to comply with the current NSPS standards for particulate matter and SO_2." (70 F.R. 62213, 62216). For new subbituminous coal-fired units with adequate water supply, EPA determined Best Demonstrated Technology (BDT) (i.e., those technologies which were the most effective at capturing mercury from coal-fired power plants) was a wet FGD/fabric filter system.

A wet FGD/fabric filter system provides better natural control of mercury than a dry FGD/fabric filter system. A supplemental mercury control system would not be required to meet the CAMR if a wet FGD system is installed, but supplemental mercury controls may be required if a dry FGD system is installed on HU-Unit2. Adding a supplemental mercury control system would substantially increase its operating and maintenance costs.

<u>Economic</u>

The applicant has proposed a voluntary limit that meets BACT criteria; therefore, an economic analysis is not necessary.

Step 5-Select BACT and Document the Selection as BACT

The lowest permitted BACT level of a wet FGD system at a new PC EGU that has been demonstrated in practice is Old Dominion in Virginia, with a permitted level of 0.10 lb/MMBtu. The lowest emission rate identified on the EPA National Coal spreadsheet is the BHP Billiton Cottonwood facility (the application is on hold) which is proposing an emission rate of 0.06 lb/MMBtu. The recent construction permit for the CPS J.K. Spruce Unit 2 facility (Texas) also has a 0.06 lb/MMBtu 12-month rolling average BACT limit.

A wet FGD system provides the lowest emissions from the proposed Hugo Unit 2. The applicant proposed a limit of 0.1 lb/MMBtu as BACT, but volunteered a limit of 0.065 lb/MMBtu based on the use of a wet FGD. AQD considers the limit of 0.065 lb/MMBtu acceptable as BACT, as it reflects a continuous removal efficiency of approximately 96% (based on the maximum expected average fuel sulfur content of 0.7% by weight) and is essentially equivalent to the lowest BACT level permitted to date. The permit limit for SO_2 emissions will be 0.065 lb/MMBtu based on a 30-day rolling average. Compliance will be demonstrated with CEMS data.

Particulate Matter (PM / $PM_{10)}$ Emissions

Step 1 - Identify All Control Technologies

Particulate matter (PM) is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. In addition, condensable PM results when gases at the stack exit condense to a liquid within a few seconds of leaving the stack. PM emissions that are less than 10 microns in diameter are referred to as PM_{10}. PM and PM_{10} are emitted from coal-fired boilers as a result of the ash contained in the coal. Ash is the inorganic matter that is not combusted in the boiler. Approximately 80% of the ash contained in the coal becomes fly ash that can be emitted as PM and/or PM_{10}.

The following add-on controls were identified as technologies available to control PM emissions form PC-fired coal boilers.

Fabric Filter Baghouse

A fabric filter baghouse (FF) removes pollutants and condensed metals (lead, beryllium, mercury, etc.) from the flue gas by drawing dust-laden flue gas through a bank of filter tubes. A filter cake, composed of the removed particles, builds up on the dirty side of the bag. Periodically, the cake is removed through physical mechanisms such as a blast of air from the clean side of the bag, or mechanical shaking of the bags, which causes the cake to fall. The dust is then collected in a hopper and removed. Fabric filters include reverse gas fabric filters (RGFF) or pulse jet fabric filters (PJFF). In a PJFF, the fly ash is collected on the outside of the bags. A PJFF can operate at higher air-to-cloth ratios than a reverse gas system. Consequently, a PJFF is smaller and will usually have lower capital costs than a RGFF. The bags in a RGFF, however, can be expected to have a longer service life. Consequently, a RGFF will typically have lower operating costs than a PJFF. For the purposes of this BACT analysis, a distinction is not made between RGFF and PJFF.

Electrostatic Precipitator (ESP)

An electrostatic precipitator (ESP) removes dust or other fine particles from the flue gas by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed. An ESP consists of a hopper-bottomed box containing rows of plates forming passages through which the flue gas flows. Centrally located in each passage are emitting electrodes energized with a high-voltage, negative polarity direct current. The voltage applied is high enough to ionize the gas molecules close to the electrodes, resulting in a corona current of gas ions from the emitting electrodes across the gas passages to the grounded collecting plates. When passing through the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream towards the grounded plates, and there they are collected in a layer. The plates are periodically cleaned by a mechanical rapping system to release the ash layer into ash hoppers as an agglomerated mass. Factors affecting the efficiency of the ESP include flue gas flow rate, resistivity of the ash, plate area, voltage, number of sections, and overall power consumption.

Wet ESP

A wet ESP operates in the same three-step process as a dry ESP: charging, collection, and removal. However, the removal of particles from the collecting electrodes is accomplished by washing of the collection plate surface using liquid, rather than mechanical rapping of the plates. Wet ESP is more widely used in applications where the gas stream has high moisture content, is below the dew point, or includes sticky particles.

<u>Mechanical Collectors followed by Particulate Scrubbers</u>

Other technologies available are mechanical collectors such as centrifugal separators (cyclones) followed by particulate scrubbers such as wet scrubbers and venturi scrubbers. However, these technologies do not achieve the removal efficiency of a fabric filter or an ESP and will not be considered further.

Step 2-Eliminate Technically Infeasible Options

A review of the RBLC and the National Coal-Fired Utility spreadsheet indicates that, for all of the power plants permitted in the United States during the previous 10 years, ESP controls and fabric filters have been the most commonly identified and selected control devices for PM emissions from all coal-fired generation projects. Wet ESPs have been proposed as secondary particulate collection on two recent permit applications and for the Thoroughbred Generating Station, but all these facilities will fire bituminous (higher sulfur coal), and the decision to select a wet ESP was associated with the reduction of H_2SO_4 mist emissions rather than to control PM_{10} specifically.

Step 3-Rank Remaining Control Technologies by Control Effectiveness

Fabric filters and ESP can both achieve high reduction efficiencies, although fabric filters have been demonstrated to reach slightly higher efficiencies.

Step 4-Evaluate Most Effective Controls for Energy, Environmental, and Economic Impacts

The applicant has selected fabric filters as the control technology for control of PM emissions, which is considered the best technology available. However, it should be noted that energy is required to operate both an ESP and fabric filters. The energy to operate a fabric filter system is estimate to be approximately 0.6 percent of the station output. This is approximately half what it would cost to operate an ESP. Adding a wet ESP after the wet scrubber could remove additional PM: however, that would involve much more capital ($22,000,000 to $40,000,000) and operating expense and is not considered economically feasible.

Step 5-Select BACT and Document the Selection as BACT

Depending on the test procedure followed, PM_{10} emissions may include both filterable and condensable emissions. To address this, some permits have established a PM limit that does not include condensable material, and a PM_{10} value (usually larger than the PM value) that includes both the filterable and condensable material. Table IV.VIII shows the range of BACT in permits in the National Coal Spreadsheet or the RBLC for PC-fired boilers. There is a wide range of BACT determined for PM emissions depending on the averaging period the limit is based on, the compliance method required (from PM monitoring to annual compliance tests), and whether a dry or wet scrubber was used for SO_2 emissions control. Since the PM control for a wet scrubber is located ahead of the scrubber, some PM emissions can be added to the clean flue gas stream by the wet scrubber. Most of the lower BACT limits for total PM listed in Table IV.II above and in Table IV.VIII below are for facilities with dry scrubbers.

Table IV.VIII PM/PM_{10} RBLC BACT Emission Limits

Pollutant	Emission Limit (lb/MMBtu)	Status of Facility
PM/PM_{10} filterable	0.013 – 0. 012 [1]	Permitted - not demonstrated
	0.015 [2]	Permitted - not demonstrated
	0.018 [3]	Demonstrated
	0.025 – 0.020 [4]	Demonstrated
PM/PM_{10} Total	0.018 [5]	Permitted - not demonstrated
	0.04 – 0.022 [6]	Demonstrated

1. Three permits.
2. Five permits.
3. Over ten permits.
4. Five permits.
5. At least three permits, perhaps more.
6. Numerous permits with about 0.03 as the most often listed.

Because almost all of the emissions from a fabric filter will be below PM_{10} in size, the PM and PM_{10} limit will be set at the same value. Controlled emissions of 0.018 lb/MMBtu have been demonstrated on PC-fired boilers with wet scrubbers. The applicant proposed a BACT limit of 0.018 lb/MMBtu. However, the EPA recently amended the NSPS Subpart Da standards for coal-fired boilers to require a limit of either 0.14 lb/MWh (gross) or 0.015 lb/MMBtu based on Best Available Technology (BAT). BACT cannot be less stringent than an applicable NSPS standard; therefore, BACT is considered to be the lower NSPS limit of 0.015 lb/MMBtu. The limit will be based on a 24-hr average. Compliance will be demonstrated in accordance with the monitoring requirements of NSPS Subpart Da.

The applicant proposed a BACT limit for PM_{10} emissions (including both the filterable and condensable emissions of PM_{10}) of 0.03 lb/MMBtu and a voluntary limit of 0.025 lb/MMBtu. This limit of 0.025 lb/MMBtu is acceptable to AQD as BACT. Compliance will be demonstrated by Reference Method stack testing and compliance with the requirements of NSPS Subpart Da for PM_{10}.

Carbon Monoxide Emissions

CO emissions are the result of incomplete combustion. Operating with higher flame temperatures and longer furnace residence times can reduce CO emissions. Unfortunately, reducing CO emissions can result in an increase of NO_X emissions from the boiler. Achieving low CO and NO_X emissions is a balancing act in the boiler design and operation.

Step 1-Identify All Control Technologies

Good Combustion Control

The only CO emissions control technology identified in the RBLC and other databases is Good Combustion Control (GCC). Modern coal-fired boilers with LNB are equipped with advanced combustion controls to help maintain boiler efficiency and low emissions. The combustion system is an effective oxidation system (i.e., minimizing CO and maximizing CO_2) and emissions of CO have traditionally been maintained very low by design. Some recent units, especially with advanced LNB, have the potential for higher emissions of CO, but good combustion control can minimize this potential.

Others

Other CO control technologies that are sometimes considered in BACT determinations, but never selected for coal-fired boilers are flares, after burning, thermal oxidation, and catalytic oxidation.

Step 2-Eliminate Technically Infeasible Options

Flares, after-burning, and thermal oxidation each add significant cost and require combustion of large quantities of natural gas which increase emissions of NO_X and other pollutants. Therefore, those technologies are always considered infeasible for coal-fired boilers. Catalytic oxidation is also considered infeasible because of catalyst plugging from particulates in the flue gas, if placed ahead of the PM control equipment, or because of the additional combustion of natural gas to reheat the flue gas if placed after the PM control device.

Since only one control option has been identified, Steps 3 and 4 are not necessary.

Step 5-Select BACT and Document the Selection as BACT

Table IV.IX shows the results of a BACT review of the RBLC and the National Coal Spreadsheet for PC-fired boilers.

Table IV.IX CO RBLC BACT Emission Limits

Pollutant	Emission Limit (lb/MMBtu)	Control Technology Description Associated with BACT Emission Limit
CO	0.135 - 0.10 [1]	GCC Permitted - not demonstrated
	0.16 - 0.15 [2]	GCC Permitted - demonstrated

1. Six permits.
2. Fifteen permits.

Recent BACT determinations on units similar to Hugo Unit 2, including the latest two permits in Texas, have limited CO emissions to 0.15 lb/MMBtu. Several permits, including the recently issued Thoroughbred Generating Station, have lower limits of 0.12 to 0.10 lb/MMBtu. The Hugo Unit 2 facility will be meeting a BACT limit for NO_X emissions equal to the lowest ever permitted; therefore, care must be taken not to impose a CO limit that could impose a restriction on the design and operation of the boiler that might affect meeting that NO_X limit. The applicant proposed a limit of 0.15 lb/MMBtu. This is acceptable to AQD as BACT. The permit limit for CO emissions will be 0.15 lb/MMBtu based on a 30-day rolling average. Compliance will be demonstrated with CEMS data.

Volatile Organic Compounds (VOC) Emissions

As for CO, VOC emissions are the result of incomplete combustion.

Step 1-Identify All Control Technologies

Good Combustion Control

The only VOC emissions control technology identified in the RBLC and other databases is Good Combustion Control (GCC). Modern coal-fired boilers with LNB are equipped with advanced combustion controls to help maintain boiler efficiency and low emissions. The combustion system is an effective oxidation system and emissions of VOC have traditionally been maintained very low by design.

Others

Other VOC control technologies that are sometimes considered in BACT determinations, but never selected for coal-fired boilers are flares, after burning, thermal oxidation, and catalytic oxidation.

Step 2-Eliminate Technically Infeasible Options

Flares, after-burning, and thermal oxidation each add significant cost and require combustion of large quantities of natural gas which increase emissions of NO_X and other pollutants. Therefore, those technologies are always considered infeasible for coal-fired boilers. Catalytic oxidation is also considered infeasible because of catalyst plugging from particulates in the flue gas, if placed ahead of the PM control equipment, or because of the additional combustion of natural gas to reheat the flue gas if placed after the PM control device.

Since only one control option has been identified, Steps 3 and 4 are not necessary.

Step 5-Select BACT and Document the Selection as BACT

There is a wide range of BACT determined for VOC emissions depending on the averaging period the limit is based on. Table IV.X shows the results of a BACT review of the RBLC and the National Coal Spreadsheet for PC-fired boilers.

Table IV.X VOC RBLC BACT Emission Limits

Pollutant	Emission Limit (lb/MMBtu)	Control Technology Description Associated with BACT Emission Limit
VOC	0.0032 – 0.0024 [1]	GCC Permitted – not demonstrated
	0.0036 – 0.0034 [2]	GCC Permitted – demonstrated
	0.007 – 0.004 [3]	GCC Permitted – demonstrated

1. Five permits at: 0.0032, 0.003, 0.0027, 0.0025, and 0.0024.
2. Nine permits.
3. Three permits.

Most of the reviewed permits listed BACT as 0.036 to 0.034 lb/MMBtu. This limit has been demonstrated on new PC-fired units. As with CO, care must be taken not to restrict VOC emissions such that it could impose a restriction on the design or operation of the boiler to meet low NO_X emissions. The applicant proposed a limit of 0.0036 lb/MMBtu. This is acceptable to AQD as BACT. Compliance will be demonstrated by Reference Method stack testing and compliance with the CO permit limit per CEMS data.

Sulfuric Acid (H_2SO_4) Mist Emissions

The majority of the sulfur in a coal-fired boiler leaves the boiler as sulfur dioxide. A small percentage of the sulfur oxides leaving a boiler will be sulfur trioxide (SO_3). As the temperature of the flue gas decreases when it passes through the economizer, SCR, and air heater, the SO_3 combines with water vapor to form H_2SO_4 vapor. In addition, the flue gas passing through the catalyst bed of an SCR system results in more of the SO_2 in the flue gas being oxidized to SO_3. Estimates of the conversion rate range from 0.2 to 1.0 percent in the boiler, and SCR vendors indicate they expect that approximately 1 percent of the SO_2 passing through the SCR will be converted to SO_3. Therefore, a total of 2 to 3 percent of the combustion SO_2 would be expected to form H_2SO_4.

Further decrease of the flue gas temperature (below the acid dew point) results in the H_2SO_4 vapor condensing to an aerosol that is emitted from the stack. Most H_2SO_4 mist particles are in a particle size range between 0.1 and 0.5 microns. At these sub micron particle sizes the light scattering phenomenon is at a maximum, so very low emissions of H_2SO_4 mist can increase the opacity of stack emissions substantially.

Step 1-Identify All Control Technologies

H_2SO_4 mist can be removed from the gas stream along with particulate matter. Until recently, no control options were identified specifically to control H_2SO_4 mist. H_2SO_4 mist control has been achieved as a co-benefit of sulfur and particulate control. It has been shown that dry scrubbers, followed by a fabric filter, achieve the highest H_2SO_4 mist reduction due to the relative location of the PM control (after the dry FGD). A few units, which are proposed to burn higher sulfur coal and rely on wet FGD for SO_2 control, have proposed a wet ESP to remove some of the remaining PM or H_2SO_4 mist emissions that are still in the flue gas after passing through the PM control and wet FGD. Also, for facilities with an ESP for PM control, alkali sorbents such as ammonia, calcium, magnesium, and sodium can be injected ahead of an ESP to increase the reduction of H_2SO_4.

Therefore, control technologies include lower sulfur fuel to reduce the available sulfur for combustion, FGD systems and PM_{10} control devices, sorbent injection for facilities with ESP for PM control, and including the addition of a wet ESP following the wet FGD system. Use of lower sulfur coal is not considered a control technology for Hugo Unit 2 since low sulfur PRB coal was selected as the fuel based on other unrelated factors.

Step 2-Eliminate Technically Infeasible Options

A dry FGD system is determined to be technically infeasible. A wet FGD has been selected for the control of SO_2 and it is not technically feasible to operate both a wet and a dry FGD system on the same unit. Sorbent injection is also considered technically infeasible since FF has been selected for PM control and not an ESP.

Step 3-Rank Remaining Control Technologies by Control Effectiveness

A fabric filter followed by a wet FGD system is expected to remove approximately 60 percent of the H_2SO_4 mist from the gas stream. A wet ESP has been installed at a few existing high sulfur coal power plants for control of H_2SO_4 mist emissions that were causing opacity problems. Reductions of over 90% have been reported.

Step 4-Evaluate Most Effective Controls for Energy, Environmental, and Economic Impacts

The most effective control for SO_2 and PM emissions has been selected as wet FGD and FF. That is the baseline control for emissions of H_2SO_4 mist at 60% control. The only other technology to evaluate is adding a wet ESP after the wet FGD.

Energy

Operating a wet ESP requires more power due to the additional pressure drop in the flue gas system (about 2 inches of water) and power consumption of the ESP. This can add about 0.1% in additional power consumption, which is not so excessive as to preclude the use of a wet ESP.

Environmental

Operating a wet ESP requires more water makeup for the power plant. The additional ESP would be expected to reduce PM emissions even further and possibly help reduce mercury emissions more than from operation of a wet FGD and FF alone. Also, operation of a wet ESP would have an aesthetic benefit of preventing the steam plume normally emitted from a power plant stack, since the wet ESP would remove condensed water vapor from the flue gas.

Economic

A detailed economic analysis was not provided by the applicant. However, installation costs for a wet ESP range from 30 to 50 $/kW, which would be in the range of $22,000,000 to $40,000,000 for the Hugo Unit 2. This installation cost alone is considered an excessive cost to remove an additional 35 to 50 tpy of H_2SO_4 mist. Since the Hugo Unit 2 will be burning low sulfur coal, it will be able to meet opacity limitations without any additional add-on control for H_2SO_4 mist.

Step 5-Select BACT and Document the Selection as BACT

Table IV.XI identifies the H_2SO_4 mist emission rates reported in the National Coal Spreadsheet and RBLC.

Table IV.XI H_2SO_4 Mist BACT Emission Limits

Pollutant	Emission Limit (lb/MMBtu)	Control Technology Description Associated with BACT Emission Limit
H_2SO_4 Mist	0.001	Dry FGD, Fabric filter, Not Demonstrated
	0.0029	Dry FGD, Fabric filter, Not Demonstrated
	0.0037 [1]	Wet & Dry FGD, Fabric filter, Not Demonstrated
	0.0044 - 0.0042 [2]	Wet & Dry FGD, Fabric filter, Not Demonstrated
	0.005 [2]	Wet & FGD, Fabric filter, Demonstrated
	0.01 – 0.006 [3]	Wet & FGD, Fabric filter, Demonstrated

1. Two permits.
2. Three permits.
3. Four permits.

The City Utilities of Springfield’s Southwest Power Station Unit 2 has a proposed emission limit of 0.00018 lb/MMBtu; however, this was not a BACT determination and is based on a spray dryer fabric filter combination which is not a similar unit to Hugo Unit 2. The Newmont Mining TS Power Plant has a BACT emission limit of 0.001 lb/MMBtu, but it is also based on a spray dryer fabric filter combination. The recently issued permits in Texas have BACT limits of 0.0037 lb/MMBtu (one unit will use a dry FGC and one will use a wet FGD). The recently issued Thoroughbred Generating Station permit has a BACT limit of approximately 0.005 lb/MMBtu. The lowest limit that has been demonstrated in practice on a similar unit and using similar technology as Hugo Unit 2 is 0.005 lb/MMBtu. The applicant proposed a limit of 0.005 lb/MMBtu. This is acceptable to AQD as BACT. Compliance will be demonstrated by Reference Method stack testing and compliance with the SO_2 permit limits per CEMS data.

Fluoride (HF) and HCL Emissions (non PSD BACT)

Fluorides and chlorides are contained in the coal that is burned in a coal-fired EGU and leave the system as hydrogen fluoride (HF) and hydrochloric acid (HCL).

Potential controls to reduce these emissions include less fluorides and chlorides in the fuel (coal washing) and the same options evaluated for control of PM and SO_2. Coal washing is considered an infeasible option for PRB coal as discussed previously. The controls selected for control of the PM and SO_2 for Hugo Unit 2 provide a co-benefit of control for HF and HCL and other pollutants. A fabric filter has been selected for the control of PM and this control device will also control HF and HCL emissions. This is because the HF and hydrochloric acid must pass through the fly ash filter cake. Downstream of the fabric filter, the wet FGD system may provide some additional collection of the HF and HCL. Therefore, fabric filter and a wet scrubber are considered as BACT by AQD. No specific limitations will be placed in the permit as compliance with the PM_{10} and SO_2 limitations and control requirements will achieve maximum reduction.

B. MATERIAL HANDLING EQUIPMENT

The following subsections address the BACT determination for the coal, limestone, and fly ash handling systems. Bottom ash will be handled wet and will be sluiced to the existing ash pond for ultimate disposal using the existing system; therefore, bottom ash is not included as an air pollution source.

Coal Handling Equipment

Rail unloading will be performed at the existing unloading hoppers where it will be discharged by vibrating feeders onto belt conveyors that move coal to a transfer tower where the coal is directed either to existing or new coal silos or to long-term storage. Coal dust is controlled at all of the existing emission points using fabric filters or water sprays. Dust will be controlled from the new storage silo using a fabric filter.

Coal can be reclaimed from long-term storage using the existing reclaim hoppers and conveyors. A new reclaim hopper and conveyor will be added. Emissions from the discharge of the silos and the reclaim transfer onto the under-silo conveyor are controlled using fabric filters and wet suppression. From the silos, the coal is conveyed to a transfer tower where the coal is either sent to stock out (wet suppression) in an active pile, or crushed and transferred to a conveyor (fabric filter control). This conveyor is enclosed and feeds the coal to the Hugo Unit 1 and Hugo Unit 2 coal silos. Fabric filters collect and control coal dust at the transfer towers, the tripper room floor and all of the coal silos. New fabric filters will be provided for the new facility silos.

Chemical surfactants and/or water suppression are currently used to minimize fugitive emissions from the coal storage pile. The large surface area of the coal storage pile makes capture of the fugitive particulate matter emissions by mechanical devices infeasible. Particulate emissions from the coal storage pile will be reduced by wet suppression, as necessary, using water and/or chemical surfactants during stock out and on the pile.

The generally accepted standard for best available control for fabric filter outlet emission rates is 0.01 grains per dry standard cubic foot (gr/dscf). This emission rate is well in excess of 99 percent particulate removal efficiency for particles larger than 3 microns. The applicant reviewed different fabric filter vendors and equipment suppliers, and determined that all new fabric filters used to control filterable particulate emissions from coal handling operations will be capable of achieving an outlet emissions rate of 0.01 gr/dscf. A review of the RBLC and recently issued permits indicates that BACT for material handling is 0.01 gr/dscf. The applicant proposed a limit of 0.01 gr/dscf from fabric filters as BACT. The proposed limit is acceptable to AQD as BACT. Initial compliance will be demonstrated in accordance with 40 CFR Part 60, Subpart Y. Continuous compliance will be demonstrated by daily checks of filter pressure drop and once daily operator inspection for visible emissions.

Limestone Handling Equipment

Control options for fugitive particulate emission from limestone handling include reducing drop distances, wind screens for drop locations, and water and surfactant sprays. These controls represent “best management practices,” and are considered to be consistent with the greatest removal efficiency and lowest emissions resulting from similar systems, and therefore represent BACT. The applicant proposed these controls as BACT. This control technology is acceptable to AQD as BACT, since only one control option exists. Compliance will be demonstrated with specific permit requirements for compliance with OAC 252: 100-29.

Control options for point source particulate emission points, including emissions from the limestone storage bins, include scrubbers, baghouses, and ESPs. In the locations required for the material handling control devices, fabric filters offer greater flexibility and operating reliability, and fabric filters are typically used. It was determined that a limit of 0.01 gr/dscf filterable particulate has been demonstrated in practice and is consistent with other BACT determinations. The applicant has proposed as BACT that all baghouses used to control particulate emissions from the delivery and handling of limestone will achieve an outlet emission rate of 0.01 gr/dscf. The proposed control limit is acceptable to AQD as BACT. Compliance will be demonstrated by daily checks of filter pressure drop and once daily operator inspection for visible emissions.

Fly Ash Handling Equipment

Control options for fly ash handling point source emissions include scrubbers, fabric filters, and ESPs. In the locations required for the material handling control devices, fabrics filters offer greater flexibility, operating reliability, and are typically used. Fabric filters are integral to the pneumatic system, and will be used to control emissions associated with loading and unloading operations from the ash silo. It was determined that a limit of 0.01 gr/dscf filterable particulate has been demonstrated in practice and is consistent with other BACT determinations. The applicant proposed as BACT that all baghouses used to control particulate emissions from the delivery and handling of limestone will achieve an outlet emission rate of 0.01 gr/dscf. The proposed control is acceptable to AQD as BACT. Compliance will be demonstrated by daily checks of filter pressure drop and once daily operator inspection for visible emissions.

C. COOLING TOWER

Particulate emissions occur from the cooling tower as a result of the total solids (suspended and dissolved metals and minerals) in the water being entrained in the air stream. Mist eliminators prevent most of the water from escaping out the top of the tower; however, some water droplets (with dissolved and suspended particulate) do escape the cooling tower and are referred to as "drift". For this analysis, as a simplifying conservative assumption, all of the particulate resulting from the drift is considered to be PM_{10}.

Step 1-Identify All Control Technologies

There are several ways to reduce drift (and resulting PM and PM_{10}) emissions from cooling towers. Process modifications could be considered, including elimination of a cooling tower by using an available water source such as a stream or nearby water reservoir or lake to provide enough water to use "once through" cooling. A standard cooling tower is similar to a once through system except the water is recycled in the tower. Another alternative is the use of air fin cooling. A third alternative is to use a hybrid system that combines some aspects of a wet and a dry system. A fourth option is the installation of modern high efficiency drift eliminators on the cooling tower.

Step 2-Eliminate Technically Infeasible Options

"Once through" cooling is not a feasible option in this location. Several studies have shown that both the dry cooling system (air fins) and the wet/dry hybrid system have an impact on system performance (i.e., reduce the available power output) during the hottest parts of the year. Since Hugo Unit 2 is a base load system, this impact to the amount of power that can be produced is significant and makes both of these options infeasible. The only feasible option at this location is a wet cooling tower with high efficiency drift eliminators. Since only one control option is feasible, Steps 3 and 4 are not necessary.

Step 5-Select BACT and Document the Selection as BACT

The applicant proposed that high efficiency drift eliminators, with the capability to reduce the potential drift to a maximum of 0.0005 percent of the circulating water flow rate, is BACT for PM_{10} control at the cooling tower. The proposed control technology is acceptable to AQD as BACT. Compliance will be demonstrated by vendor guarantees.

D. WASTEWATER BRINE CONCENTRATOR AND SPRAY DRYER

The water treatment system for Hugo Unit 2 may include a brine concentrator and a spray dryer to reduce the resulting brine to a dry powder. There are no emissions (other than water vapor) expected to result from the brine concentrator. The spray dryer requires heated air, and the fuel burned to produce this heat produces some emissions.

There were no similar systems described in the RBLC, and the applicant is not aware of any other applications of this technology where post combustion air pollution control was applied. No controls have been identified for the external combustion of diesel fuel in similar installations. However, most modern large boilers and process heaters (above 10 MMBtu/hr) can be equipped with LNB to achieve lower NO_X emissions. Add-on controls for this type of installation are either unavailable or cost prohibitive.

Renewable energy sources such as solar power are not feasible for this installation due to the need to have energy available 24 hours a day. Alternative fuels for Hugo Unit 2 include propane, No. 6 fuel oil, No.2 fuel oil, or natural gas firing. Natural gas is not available at the site, and is therefore not technically feasible. Similarly, No. 6 fuel oil and propane are not being used on-site and do not offer a significant advantage from either an environmental, energy, or economic reason. Therefore, these options are also considered infeasible for this specific installation.

Low sulfur No. 2 distillate fuel oil is available on-site and is the only fuel considered to be feasible for providing heated air for the spray dryer. Emissions from the combustion of No. 2 fuel oil include NO_X, PM_{10}, VOC, SO_2, and CO. A review of the RBLC does not indicate any controls that have been identified as BACT for similar systems; however, Lox-NO_X Burners (LNB) is generally considered BACT for combustion of liquid fuels in boilers and process heaters. The AP-42 factor for heaters of less than 100 MMBtu/hr equipped with LNB is 50% of those for uncontrolled emissions (10 lb/Mgal versus 20 lb/Mgal).

The applicant proposed BACT for the control of SO_2 as the use of low sulfur No. 2 fuel oil (less than 0.5% sulfur by weight). The proposed fuel is acceptable to AQD as BACT.

The applicant proposed BACT for the control of NO_X as LNB with a limit of 10 lb/Mgal, which is equivalent to 0.07 lb/MMBtu. The proposed technology and limit is acceptable to AQD as BACT.

The applicant proposed BACT for control of PM_{10}, VOC, and CO emissions as good combustion control. The proposed control is acceptable to AQD as BACT.

E. EMERGENCY DIESEL INTERNAL COMBUSTION (IC) ENGINES

Potential alternative fuels for Hugo Unit 2 include propane, No. 6 fuel oil, No. 2 fuel oil, or natural gas firing. Natural gas is not available at the site and is, therefore, not technically feasible. Similarly, No. 6 fuel oil and propane are not being used on-site and do not offer a significant advantage from either an environmental, energy, or economic reason. Therefore, these options are also considered infeasible for this specific installation. Low sulfur No. 2 fuel oil is available on-site and is the only fuel considered to be feasible.

A review of the RBLC does not indicate any controls that have been identified as BACT for similar emergency engines with limited annual hours of operation. A review of available technology identified low sulfur fuel for the control of SO_2, catalytic controls for NO_X, and the use of an oxidation catalyst for the control of VOC and CO emissions. The NO_X catalyst system and the oxidation catalyst system are add-on controls that convert NO_X to nitrogen and oxygen, convert the CO to CO_2, and oxidize some of the VOC. The catalyst material is similar to the catalytic converters used on automobiles and is typically metal based and become potential hazardous wastes. All add-on controls are considered as economically infeasible for this type of installation due to the minimum hours of operation. Therefore, add-on catalytic controls have been eliminated as a possible emission reduction strategy.

The applicant has proposed BACT for the control of SO_2, NO_X, PM_{10}, VOC, and CO emissions resulting from the combustion of fuel oil for the emergency generator and emergency fire water pump as the use of low sulfur No. 2 fuel oil combined with good combustion practices and limited annual operation. The proposed control is acceptable to AQD as BACT. Operation of these emergency units will be limited to 52 hours each annually, unless due to emergency circumstances.

F. Emissions from Startup, Shutdown, and Malfunction (SSM)

Due to a number of factors such as tube wall and tube bank stresses, steam turbine heat up cycles, and safety concerns, pulverized coal-fired boilers require a significant amount of time to bring online from a cold start and to reach complete shutdown from normal operating conditions. Also, a startup fuel such as fuel oil is used to initiate the boiler firing until sufficient heat is obtained to begin coal firing. Some of the add-on pollution control equipment is not functional or not fully functional during these startup and shutdown periods. For instance, an SCR cannot reduce NO_X emissions significantly until a minimum flue gas temperature is obtained and, also, channeling can occur in the catalyst at reduced flue gas flow rates. The bag filter is not online while the boiler is fired with fuel oil. CO emissions can vary substantially during startup and shutdown conditions as air to fuel ratios are varying. SO_2 emissions do not vary as much since operation of the wet scrubber is not as affected significantly by boiler operations.

In order to address these situations as part of the BACT analysis and compliance with the BACT limits, the permit will define appropriate boiler operating conditions and limits that can be considered as startup and shutdown. Emissions during these periods can vary substantially from steady state operation and, therefore, will not be included in determination of compliance with the BACT limits. However, the permittee will be required to operate the boiler and pollution control equipment in accordance with good combustion practices to minimize emissions during these time periods. The permittee will also be required to retain records of these time periods and identify the measures taken to mitigate emissions.

SECTION VI. AIR QUALITY IMPACTS

Net emission increases of SO_2, CO, NO_X, PM_{10}, mercury, lead, beryllium, fluorides, and H_2SO_4 mist are greater than the significant emission rate threshold of PSD, and emissions of VOC are greater than 100 TPY. Therefore, an ambient air impact analyses is required for each of these pollutants. First, air dispersion modeling is performed to determine if any air impacts will exceed a significant ambient impact level (SAIL) or monitoring exemption level. If a SAIL is exceeded, then a full impact analysis (consisting of compliance with the NAAQS and with PSD increment consumption) is required for that pollutant. If a SAIL is not exceeded, then no further air quality analysis is required for that pollutant.

A. Description of Air Quality Dispersion Model and Procedures

Dispersion Models and Inputs

The air quality modeling analyses employed the latest versions of EPA's Industrial Source Complex Short-Term (ISCST3) dispersion model to determine ambient concentrations of NO_X, CO, PM_{10}, and SO_2 at and beyond the facility fence line. The ISCST3 model was used to determine impacts at a discrete set of off-site receptors and to identify the worst-case (highest impact) load scenarios for the ISC3 modeling. The models and associated input options are presented in the following sections.

The ISC3 model consists of two programs: a short-term model (ISCST3) and a long-term model (ISCLT3). The difference in these programs is that the ISCST3 program utilizes an hourly meteorological database, while ISCLT3 is a sector-averaged program using a frequency of occurrence based on categories of wind speed, wind direction, and atmospheric stability. The ISCST3 model was used for all pollutants. The default options selected are given below:

<u>Model Input Options</u>

1. The regulatory default options:
   a) Stack-tip downwash (except for Schulman-Scire downwash).
   b) Buoyancy-induced dispersion (except for Schulman-Scire downwash).
   c) No gradual plume rise.
   d) Calms processing routine.
   e) Default wind speed profile exponents.
   f) Default vertical potential temperature gradients.
   g) Upper-bound concentration estimates for sources influenced by building downwash from super-squat buildings.
2. Rural dispersion parameters (see below).
3. Building downwash parameters (see following).

<u>Land Classification</u>

Land use within three kilometers of the facility was classified according to the method developed by Auer (1978) using the most recent version of the United States Geological Survey (USGS) 7.5-minute topographic maps for the Fort Towson and Frogville quadrangles. The land use within a 3 kilometer radius is almost exclusively rural. Since more than 50 percent of the land use is classified as rural, rural dispersion coefficients were used.

Building Downwash

EPA's Building Profile Input Program (BPIP) was used to compute Good Engineering Practice (GEP) stack heights for each emission source (see "GEP Stack Height and Plume Downwash" following). The program then computed direction-specific building dimensions (height and projected width) for each non-GEP stack to be modeled. These dimensions were used by the ISC3 model to simulate downwash effects for each point source exhausting at heights less than GEP stack height. All stacks at the facility were characterized as non-GEP stacks, except the HU-Unit2 boiler stack.

Receptors

Receptors were modeled along the facility fence line and at off-site locations within a ten-by-ten kilometer Cartesian grid to determine the significant impact area for each pollutant. The receptors along the facility fence line were placed at 50 meter intervals. The grid incorporates the following spacing between receptors: 100 meters out to three kilometers, 250 meters out to five kilometers, and 1,000 meters out to ten kilometers from the fenceline. The significant impact area did not exceed 10 kilometers from the fenceline for any of the steady-state emission rates; therefore, it was not necessary to extend the grid to encompass the entire SIA.

The SIA for PM_{10} and SO_2 was within the twenty-by-twenty kilometer grid; therefore, the same grid was used for PM_{10} and SO_2 refined modeling. It was also verified that the maximum impact for the NAAQS and increment modeling occurred within the SIA grid.

Receptor elevations along the fence line and at the grid locations were obtained from the 7.5-minute USGS topographic maps and 7.5-minute USGS Digital Elevation Models (DEM) for the area.

Meteorology

Meteorological data representative of the site is required as an input to the ISCST3 dispersion model to estimate ambient impacts. In lieu of an on-site data set, dispersion modeling with five years of meteorological data is required. The surface data collected at Longview, Texas for the calendar years 1989-1993 and the upper air data collected at Shreveport, Louisiana for the calendar years 1989-1993, were used to model sources located in Choctaw County, Oklahoma, in accordance with AQD guidance. These data were processed using PCRAMMET into an ISC3-ready format and include wind speed and direction, stability, temperature, and mixing heights.

A worst-case operating scenario representative of normal operating conditions was determined to assess short-term SO_2, CO, and PM_{10} impacts using the ISCST3 model. As described earlier, HU-Unit2 is expected to operate between approximately 60 and 100 percent load during normal operation. Because short-term SO_2, CO, and PM_{10} emissions are not varied with load, ambient impacts were assessed for each boiler at 25, 50, 75, and 100 percent load. These impacts were assessed at an array of receptors, in which the elevation at each receptor was assumed to be the greatest elevation at that distance in any direction from the facility. The dimensions of a nearby building were used to simulate downwash effects on the stacks. This structure was determined to result in maximized building downwash effects for the stacks by the BPIP software described previously.

GEP Stack Height and Plume Downwash

The stack height regulations promulgated by EPA on July 8, 1985 (50 CFR 27892), established a stack height limitation to assure that stack height increases and other plume dispersion techniques would not be used in lieu of constant emission controls. The regulations specify that GEP stack height is the maximum creditable stack height which a source may use in establishing its applicable State Implementation Plan (SIP) emission limitation. For stacks uninfluenced by terrain features, the determination of a GEP stack height for a source is based on the following empirical equation:

$$H_g = H + 1.5L_b$$

where:

H_g = GEP stack height;
H = Height of the controlling structure on which the source is located, or nearby structure; and
L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto a plane perpendicular to the direction of the wind. The area in which a nearby structure can have a significant influence on a source is limited to five times the lesser dimension (height or width) of that structure, or within 0.5 miles (0.8 kilometers) of the source, whichever is less. The methods for determining GEP stack height for various building configurations have been described in EPA's technical support document (EPA, 1985).

Since the heights of exhaust stacks at the facility are less than the respective GEP stack heights, a dispersion model to account for aerodynamic plume downwash was necessary in performing the air quality impact analyses.

Since downwash is a function of projected building width and height, it is necessary to account for the changes in building projection as they relate to changes in wind direction. Once these projected dimensions are determined, they can be used as inputs to the ISC3 model.

In October 1993, EPA released the BPIP to determine wind direction-dependent building dimensions for input to the ISC3 model. The BPIP program builds a mathematical representation of each building to determine projected building dimensions and its potential zone of influence. These calculations are performed for 36 different wind directions (at 10 degree intervals). If the BPIP program determines that a source is under the influence of several potential building wakes, the structure or combination of structures which has the greatest influence (h_b + 1.5 l_b) is selected for input to the ISCST3 model. Conversely, if no building wake effects are predicted to occur for a source for a particular wind direction, or if the worst-case building dimensions for that direction yield a wake region height less than the source's physical stack height, building parameters are set equal to zero for that wind direction. For this case, wake effect algorithms are not exercised when the model is run. The building wake criteria influence zone is 5 l_b downwind, 2 l_b upwind, and 0.5 l_b crosswind. These criteria are based on recommendations by EPA.

Due to the relatively high, but less than GEP, stack heights, and the relatively small size of the dominant structures, the building cavity effects that were considered in the modeling analysis were minimal. For this analysis, the first step was to determine the building cavity height based on the formula:

$$h_c = H + 0.5L_b$$

where:

- h_c = GEP stack height;
- H = Height of the controlling structure on which the source is located, or nearby structure; and
- L_b = Lesser dimension (height or width) of the controlling structure on which the source is located, or nearby structure.

If the stack height was greater than or equal to the cavity height, the cavity effect would not affect the downwind maximum impacts. However, if a cavity effect was possible, the length of the cavity was compared to the distance to the nearest receptor.

Due to the size of the property, the location of the sources on the property, the height of the stacks, and the distance of the sources from the fence line, cavity effects were only encountered at the boiler building, turbine building, and ancillary structures. After running the BPIP model, the GEP stack height for HU-Unit2 exceeded 65 meters. The existing boiler building had the greatest impact on GEP with a height of 81.38 meters and a maximum projected width of 73.05 meters. Using the GEP formula yielded a GEP of 190.95 meters for the HU-Unit2 stack.

Modeled Emission Rates and Stack Parameters

The modeled stack point source parameters and emission rates for the Hugo Generating Station are shown in Table VI-1 through Table VI-3 below. Emission rates modeled for HU-Unit2 were based on BACT rates originally submitted in the application. Fugitive sources that were modeled are not listed; however, that information is listed in the permit application.

Table VI-1. Stack Parameters for Material Handling Equipment (Point Sources)

Source	Stack Height (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (°F)
HU-Coal1, P-3A	7	6.91	0.033	Ambient
HU-Coal1, P-3B	7	6.91	0.033	Ambient
HU-Coal1, P-3C	7	6.91	0.033	Ambient

Source	Stack Height (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (°F)
HU-Coal1, P-3D	7	6.91	0.033	Ambient
HU-Coal1, P-3E	7	4.31	0.033	Ambient
HU-Coal2, P-4A	24	4.31	0.033	Ambient
HU-Coal2, P-4B	229	2.15	0.033	Ambient
HU-Coal7, P-25	230	2.00	53.0	Ambient
HU-Coal2, P-4C	6	3.40	0.033	Ambient
HU-Coal7, P-26	7	3.80	50.0	Ambient
HU-Coal3, P-5A	77	2.64	0.033	Ambient
HU-Coal3, P-5B	188	2.64	0.033	Ambient
HU-Coal8, P-27	275	3.75	49.8	Ambient
HU-Ash6, P-30	135	1.50	0.033	Ambient
HU-Ash6, P-31	135	1.50	0.033	Ambient
HU-Ash2, P-14A	99	1.00	0.033	Ambient
HU-Ash2, P-14B	99	1.00	0.033	Ambient
HU-Ash8, P-33	48	1.50	57.0	Ambient
HU-Ash8, P-34	48	1.50	57.0	Ambient
HU-Ash10, P-36	81	1.00	63.0	Ambient
HU-Ash10, P-37	81	1.00	63.0	Ambient
HU-LS1, P-47	6	1.20	44.2	Ambient
HU-LS2, P-48	6	1.90	52.9	Ambient
HU-LS3, P-49	110	0.50	34.0	Ambient
HU-LS4, P-50	110	0.50	34.0	Ambient

Table VI-2. Stack Parameters for Point Sources

Source		Stack Height (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (°F)
HU-Unit2, P-24	100%	625	28.5	60.0	135
	75%	625	28.5	45.0	135
	50%	625	28.5	30.0	135
	25%	625	28.5	15.0	135
HU-G, P-38		25	0.67	1,014	900
HU-G, P-39		15	1.50	100	900
HU-SD, P-51		50	1.17	58.5	425
HU-Unit1, P-1		500	26.0	47.0	260
HU-Aux, P-2		215	8.00	19.0	260
HU-G, P-22		10	0.42	0.03	700
HU-G, P-23		7	0.29	0.03	820
HU-CT2, P-54		60	32.0	8.52	85
HU-CT2, P-54		60	32.0	8.52	85

Source	Stack Height (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (°F)
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT2, P-54	60	32.0	8.52	85
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91

Source	Stack Height (ft)	Stack Diameter (ft)	Stack Velocity (ft/sec)	Stack Temperature (°F)
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-52	73	28.0	33.0	91
HU-CT1, P-53	73	28.0	34.6	84
HU-CT1, P-53	73	28.0	34.6	84

Table VI-3. Stack Emission Rates

Source	NO_X (lb/hr)	CO (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)
HU-Coal1, P-3A	-	-	3.18×10^{-3}	-
HU-Coal1, P-3B	-	-	3.18×10^{-3}	-
HU-Coal1, P-3C	-	-	3.18×10^{-3}	-
HU-Coal1, P-3D	-	-	3.18×10^{-3}	-
HU-Coal1, P-3E	-	-	4.45×10^{-3}	-
HU-Coal2, P-4A	-	-	0.07	-
HU-Coal2, P-4B	-	-	0.07	-
HU-Coal7, P-25	-	-	0.07	-
HU-Coal2, P-4C	-	-	0.11	-
HU-Coal7, P-26	-	-	0.05	-
HU-Coal3, P-5A	-	-	0.05	-
HU-Coal3, P-5B	-	-	0.05	-
HU-Coal8, P-27	-	-	0.05	-
HU-Ash6, P-30	-	-	0.58	-
HU-Ash6, P-31	-	-	0.58	-
HU-Ash2, P-14A	-	-	0.58	-
HU-Ash2, P-14B	-	-	0.58	-
HU-Ash8, P-33	-	-	0.58	-
HU-Ash8, P-34	-	-	0.58	-
HU-Ash10, P-36	-	-	0.58	-
HU-Ash10, P-37	-	-	0.58	-
HU-LS1, P-47	-	-	3.1×10^{-3}	-
HU-LS2, P-48	-	-	0.01	-
HU-LS3, P-49	-	-	0.01	-

Source		NO_X (lb/hr)	CO (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)
HU-LS4, P-50		-	-	0.01	-
HU-Unit2, P-24	100%	498.8 *	1,068.8	213.8 *	712.5 *
	75%	374.1 *	801.6	160.3 *	534.4 *
	50%	249.4 *	534.4	106.9 *	356.3 *
	25%	124.7 *	267.2	53.4 *	178.1 *
HU-G, P-38		16.3	3.51	1.16	1.08
HU-G, P-39		41.6	6.36	1.71	4.55
HU-SD, P-51		2.86	0.71	0.22	1.01
HU-Unit1, P-1		1,027.1 [+]	11,977	62.5	4,591.8
HU-Aux, P-2		55.2	9.86	55.2	147
HU-G, P-22		19.5	4.21	1.39	1.29
HU-G, P-23		8.84	1.90	0.63	0.58
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-
HU-CT2, P-54		-	-	0.308	-

Source	NO_X (lb/hr)	CO (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)
HU-CT2, P-54	-	-	0.308	-
HU-CT2, P-54	-	-	0.308	-
HU-CT2, P-54	-	-	0.308	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-52	-	-	1.60	-
HU-CT1, P-53	-	-	2.25	-
HU-CT1, P-53	-	-	2.25	-

* Based on original application proposed BACT levels for NO_X (0.07 lb/MMBtu), SO2 (0.1 lb/MMBtu), and PM_{10} (0.03 lb/MMBtu).

\+ 1,027 lb/hr based on 4,498.8 TPY NO_X permit limit. Emissions averaged 940 lb/hr over the last three years.

B. Significant Impact Analysis

An analysis was conducted to determine if NO_2, CO, SO_2, PM_{10}, mercury, lead, beryllium, fluorides, and H_2SO_4 mist emissions from the proposed modification would result in off-site ambient impacts at levels greater than the significant ambient impact levels (SAIL) and/or the monitoring significance levels. The SAIL and monitoring significance levels for these pollutants are presented in Table VI-4.

Table VI-4. Ambient Air Modeled Impacts

Pollutant	Averaging Period	Maximum Impacts (ug/m^3)	Significant Ambient Impact Level (ug/m^3)	Monitoring Significance Level (ug/m^3)
NO_2	annual	0.4	1	14
CO	1-hour	101	2,000	-
	8-hour	23	500	575
PM_{10}	24-hour	27	5	10
	annual	3.5	1	-
SO_2	3-hour	28	25	-
	24-hour	8.3	5	13
	Annual	0.4	1	-
Lead	Calendar Quarter	0.0002	-	0.1
Fluorides	24-hour	0.02	-	-
Mercury	24-hour	0.0004	-	-
Beryllium	24-hour	0.0002	-	-
H_2SO_4 Mist	24-hour	0.3	-	-

Modeled impacts of PM_{10} (24-hour and annual average) and SO_2 (3-hour and 24-hour) emission increases associated with Hugo Unit 2 exceed the SAIL; therefore, a full impact analyses for these pollutants was required. Also, since VOC emissions exceed 100 TPY, a full impact analyses for ozone was required.

C. Ambient Monitoring

PM_{10}

The ambient impact "monitoring de minimis level" for PM_{10} is 10 µg/m^3 (24-hour average). Since the highest sixth high (H6H) modeled impact from this modification (27 µg/m^3) exceeded the PM_{10} de minimis level, the need for ambient monitoring data is indicated.

Based on the *Ambient Monitoring Guidelines for PSD* (EPA-450/4-87-007, May 1987), if the proposed source will be constructed in an area that is generally free from the impact of other point sources and area sources associated with human activities, monitoring data from a "regional" site may be used as representative data. Such a site could be out of the maximum impact area, but must be similar in nature to the impact area. This site would be characteristic of air quality across a broad region including that in which the proposed source or modification is located.

The WFEC facility is located in a relatively remote area that is generally free from the impact of other point sources and area sources associated with human activities. The nearest major source is 20 km east of the facility and there are no other major sources within 50 km. There is only one minor source located in the area and it is approximately 7 km southwest of the facility. The nearest major city is Hugo (population 5,600) which is approximately 18 km west of the facility.

The terrain in the region surrounding the WFEC Hugo facility and considered in the modeling domain is not considered complex terrain and is relatively flat.

The maximum impact from the NAAQS modeling is at the fenceline. The area in which the 10 $\mu g/m^3$is exceeded is a 400 m (E-W) by 1,200 m (N-S) area on the west central side of the facility. The emissions that contribute the majority of the impact to this area are the volume sources used to represent the North and South Coal Piles and associated activities which are located relatively close to the west fenceline. Monitors are recommended to be sited within the isopleth that represents 1/2 of the standard. The 5 $\mu g/m^3$ isopleth (line that defines where 5 $\mu g/m^3$ is exceeded) extends, at its maximums, 1.5 km north, 0.9 km south, and 1.2 km west of the facility fenceline.

The background concentration used to determine compliance with the NAAQS were taken from a monitor located in McAlester, Oklahoma (population 17,800) which is larger and has more sources impacting the monitor then the area where WFEC is located. This monitor was considered representative to conservative monitoring data of the air quality across the southeast portion of Oklahoma.

The H6H ambient impact from the NAAQS modeling of 34 $\mu g/m^3$, plus the background concentration from a regional monitor, the highest-fourth-high concentration at the McAlester monitor over the last three years (2005-2003), of 47 $\mu g/m^3$ gives a final concentration of 81 $\mu g/m^3$, which is less than 50% of the NAAQS (150 $\mu g/m^3$). Even if the highest recorded monitoring value in the state of Oklahoma, the highest-fourth-high concentration at the Tulsa monitor over the last three years (2005-2003), is used as the background concentration (107 $\mu g/m^3$), the predicted maximum impact from the Hugo facility (141 $\mu g/m^3$) would be in compliance with the NAAQS. PM_{10} monitoring for sources that have an impact of <80% of NAAQS are only required to monitor once every six days.

To summarize, preconstruction monitoring will not be required, because (1) the WFEC facility is located in a relatively remote area that is not considered an area of multi-source emissions or an area of complex terrain, and a regional monitor was approved for use in determining a conservative background concentration; (2) the area in which the monitoring de minimis level was exceeded is relatively small and, if monitoring was required, the frequency of the monitoring would be the minimum amount of monitoring required; (3) any monitoring would be relatively close to the facility fenceline; and (4) the impacts are due mainly to close by fugitive emissions sources.

Ozone

Pre-construction monitoring for ozone is required for any new source or modified existing source located in an unclassified or attainment area with greater than 100 tons per year of VOC emissions. Continuous ozone monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification.

In accordance with the "Ambient Monitoring Guidelines for Prevention of Significant Deterioration", EPA-450/4-87-007, existing monitoring data can be used to meet this requirement. The existing monitoring data should be representative of three types of areas: (l) the location(s) of maximum concentration increase from the proposed source or modification, (2) the location(s) of the maximum air pollutant concentration from existing sources, and (3) the location(s) of the maximum impact area, i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of existing sources and the proposed new source or modification.

The locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources. In situations where there is no existing monitor in the modeled areas, monitors located outside these three types of areas may be used. Each determination must be made on a case-by-case basis. The EPA guidance on this issue is not designed for the evaluation of a secondary pollutant like ozone and the guidance document clearly discusses the evaluation of the impact of primary pollutants. However, a demonstration that existing monitoring data for ozone is representative of the three areas listed above can be made.

Photochemical modeling results were generated using the SIP modeling database for the EAC. The SIP modeling was conducted following EPA guidance and has been reviewed and accepted by EPA. Adding to the SIP database the maximum potential emissions from this project, maximum impacts from this project were observed in Choctaw County. There are no ozone monitors in Choctaw County. The modeling conducted for the EAC provided information on the impact of local facilities on the air quality of Choctaw County. Modeling was conducted for an ozone episode in which concentrations were at their peak and predicted concentrations for Choctaw County were all below the standard and were comparable to those predicted for McCurtain, Pushmataha, and Pittsburg Counties. Weyerhaeuser installed an ozone monitor during the 2005 ozone season approximately 18 miles ENE of the Hugo facility in order to comply with a PSD permit issued for the Valliant Mill. The monitor was sited to capture maximum impacts from the Weyerhaeuser facility. However, this monitoring data does provide a conservative snapshot background concentration for the Hugo facility. The fourth high eight-hour concentration at the Weyerhaeuser monitor was 80 ppb over four months of monitoring during the 2005 ozone season. A more accurate long term background monitor for the southeast portion of the state is located in Pittsburg County (No. 401210415). The 2003-2005 design value for the Pittsburg monitor is 71ppb.

D. Full Impact Analysis (NAAQS and PSD Increment)

Ozone

The potential increase in emissions of NO_X from the project is approximately 1,600 TPY and the potential increase in emissions of VOC is 113 TPY. OAC 252:100-8-35 requires an air quality impact evaluation for each regulated pollutant for which a major modification would result in a significant net emissions increase. No de minimis air quality level is provided for ozone. However, any net increase of 100 tons per year or more of VOC subject to PSD is required to perform an ambient impact analysis. Methods for evaluating single source impacts on ozone concentrations are not consistent, due to the lack of availability of data at a refined level, readily available tools, and EPA guidance. DEQ has evaluated the impact of the proposed modification to the Hugo facility using an existing air quality database generated for a SIP evaluation and the CAMx photochemical modeling system.

Oklahoma entered into Early Action Compact (EAC) agreements with EPA for the Tulsa and Oklahoma City metropolitan areas. Photochemical modeling evaluations were prepared in support of the agreements. These evaluations were conducted in accordance with EPA guidance and underwent an extensive public comment process and EPA review. The modeling was based on a two week episode beginning in Mid-August of 1999 and extending through the first week of September 1999. This episode was chosen both by virtue of being a prolonged period of high ozone concentrations and a reflection of the most common meteorological conditions that spawn high ozone concentrations for Tulsa and Oklahoma City.

Modeling for Hugo was conducted using the EAC 2007 control case. Emissions to be modeled were calculated by adding the future potential increases identified in the application to the 2007 grown emissions. VOC emissions were further speciated by Source Classification Code, SCC, using speciation tables generated by EPA and SCCs for Hugo processes as identified in annual inventories and project inventories.

Maximum impacts from the proposed increases occur in Choctaw County, southern portions of Pushmataha County and western portions of McCurtain County. A maximum 8-hour increase of 7 ppb was predicted in Choctaw County in the immediate vicinity of the facility. This impact is due to NO_X emissions and not VOC. NO_X generally reacts more rapidly than VOC in air masses. NO_X is removed preferentially and in rural areas (VOC dominated) downwind of large NO_X sources a localized increase in ozone concentrations should be expected. Maximum downwind impacts in adjoining counties were less than 5ppb dropping off to less than 1ppb over a very short distance. Maximum downwind impacts in Tulsa and Oklahoma City were negligible. Impacts in Oklahoma City were less than 0.1 ppb. Impacts in Tulsa were 0.1 ppb or less. The highest current design value for Tulsa (2003-2005) is 79 ppb. The highest current design value for Oklahoma City is 79ppb.

In summary, use of the existing monitoring data collected in McCurtain and Pittsburg Counties along with modeled corroboration is adequate to establish existing air quality in the vicinity of the proposed source and to demonstrate maximum impacts.

PM_{10} and SO_2

A full impact analysis requires the development of emission inventories of nearby sources. Nearby sources are defined as any point source expected to cause a significant concentration gradient within the significant impact area (SIA). This includes sources in adjacent states.

There are two steps required to determine which facilities qualify as "nearby facilities." First, the region in which all sources must be initially classified as "nearby sources" must be defined. This region extends to 50 kilometers (km) beyond the largest pollutant-specific SIA. A pollutant-specific SIA is the region within which the pollutant impacts are expected to exceed the SAIL. In this case, the PM_{10} SIA extends approximately 5 km from the center of the facility, and SO_2 impacts extend 18.3 km (3 hr averaging period) and 8.0 km (24 hr averaging period) from the center of the facility (values determined from dispersion modeling). All facilities that emit the pollutant for which the full analysis is being performed and that fall within a 50 km radius of the pollutant-specific SIA are to be considered for inclusion in the modeling analysis. Therefore, for this analysis, all sources of PM_{10} within 55 km of the facility and SO_2 sources within 70 km are to be considered nearby sources unless they are otherwise disqualified. NO_X and CO emissions do not exceed the SAIL level; therefore an SIA is not triggered.

The second step in determining nearby sources requires calculating a ratio of the total facility emissions to the distance from the proposed facility. AQD has issued guidance stating that use of the "Louisiana 20-D Rule" is acceptable for eliminating nearby sources. According to the guidance document, "when a nearby source's emissions (TPY) are less than 20 times the distance between the nearby source and the source in question (in kilometers), that source may be designated a background source and not modeled." Potential nearby sources from Texas, Oklahoma, and Arkansas were modeled. Thirty-five (35) sources were modeled for SO_2 and twenty-four sources were modeled for PM_{10}. The specific sources, their location, stack parameters, and emission rates are listed in the application.

Background concentrations for PM_{10} were taken from a monitoring station in McAlester, Oklahoma. Background concentrations for SO_2 were taken from a monitoring station in Muskogee, Oklahoma. These stations are considered to provide conservative background concentrations for the proposed facility.

The *Guideline on Air Quality Models* (GAQM, Table 9.2, Attachment W to 40 CFR Part 51), requires that short-term impacts from combustion sources subject to the PSD regulations be evaluated for maximum design capacity as well as for any normal operating condition that can lead to higher ambient impacts due to changes in source parameters. The GAQM also requires that annual impacts for these sources be evaluated at maximum design capacity. Short-term impacts of CO, PM_{10}, and SO_2 were assessed for various load conditions throughout the normal operating range of HU-Unit2 boiler (i.e., 100, 75, 50, and 25 percent loads). The hourly emission rates of CO, PM_{10}, and SO_2 were held constant while other source parameters were varied with the operating load. Modeling runs were conducted at full load and partial loads to confirm that operation of Hugo Unit 2 will not result in impacts greater than the NAAQS or PSD Class II Increments.

<u>Modeling Results</u>

The maximum predicted impacts for PM_{10} (24-hour and annual average) and SO_2 (3-hour and 24-hour) for the NAAQS modeling are summarized in Table VI-5. The high-2nd high was used for the 3-hour and 24-hour averaging period analysis for SO_2, and the highest 6^{th}-high (Pre-1997

Method) over five years of data was used for the 24-hr averaging period analysis for PM_{10}. The highest mean value was used for the SO_2 analysis and the highest five year average was used for the PM_{10} annual standards. As shown, the sum of the predicted impacts and background concentrations are less than the corresponding NAAQS. Therefore, the proposed modification, in conjunction with existing sources, will not cause or contribute to a violation of the NAAQS standard for PM_{10} and SO_2 (all averaging times).

Table VI-5. NAAQS Model Results

Pollutant	Averaging Time	Impact (ug/m^3)	Background (ug/m^3)	Background + Impact (ug/m^3)	NAAQS (ug/m^3)
PM_{10}	24-hour [A]	34	47	81	150
	Annual [B]	5	22	27	50
SO_2	3-hour [C, D]	180	149	329	1,300
	24-hour [D]	65	55	120	365

A. Values are highest 6th-high
B. Values are the highest 5-year average
C. Secondary standard
D. Values are high-2nd high

The increment modeling results for PM_{10} (24-hour and annual average) and SO_2 (3-hour and 24-hour) impacts are summarized in Table VI-6. The PSD increment analysis compares all increment consuming emission increases in the area of impact since the baseline date against the available increment. The amount of available increment is based on other sources constructed within the area of impact since the baseline date. The minor source baseline date was triggered for all counties within the radius of impact by an earlier project. Minor increases and decreases at existing major facilities may impact the increment consumption prior to the minor source baseline date. The high-2nd high was used for the 3-hour and 24-hour averaging period analysis for SO_2, and the highest 6th-high (Pre-1997 Method) over five years of data was used for the 24-hr averaging period analysis for PM_{10}. The highest mean value was used for the SO_2 analysis and the highest five year average was used for the PM_{10} annual standards. As shown in Table VI-5, the predicted impacts are less than the corresponding available PSD Class II increment. Therefore, the proposed facility, in conjunction with existing sources, will not cause or contribute to a violation of any PSD increment standard for PM_{10} and SO_2 (all averaging times). Adequate increment is available for the proposed modification and other nearby increment consumers.

Table VI-6. Increment Modeling Results

Pollutant	Averaging Time	Impact (ug/m^3)	Available PSD Class II Increment (ug/m^3)
PM_{10}	24-hour [A]	27	30
	Annual [B]	4	17
SO_2	3-hour [C]	126	512
	24-hour [C]	35	91

A. Values are highest 6th-high
B. Values are the highest 5-year average
C. Values are high-2nd high

SECTION VII. ADDITIONAL PSD IMPACTS ANALYSES

Additional impact analyses were conducted to assess the impairment to Class I areas, visibility, soils, and vegetation that would occur as a result of the modification and any commercial, residential, industrial, and other growth associated with the facility. These analyses are discussed in the following sections.

Class I Area Impacts Analysis (First Supplemental Class I Air Quality Modeling Analysis)

An air quality analysis was performed on the proposed HU-Unit2 to demonstrate that the new unit will comply with PSD permitting requirements for Class I areas. The modeling analysis evaluated air quality and air quality related value (AQRV) impacts at the Caney Creek Wilderness Area (CCWA), located approximately 113 kilometers or approximately 73 miles to the northeast of the Hugo Generating Station. A Class I area is an area of the country with special national or regional value from a natural, scenic, recreational, or historic perspective. These Class I areas are afforded special protection to minimize the impacts of new sources on their air quality.

A Class I area impact analysis consists of two parts:

1. PSD Class I Increment Analysis. Increment is the maximum increase in ambient pollutant concentrations allowed over baseline concentrations. SO_2, NO_2, and PM_{10} were the pollutants analyzed.
2. AQRV Analysis. AQRVs are special attributes of a Class I area that deterioration of air quality may adversely affect. These attributes often include flora and fauna, water, visibility, cultural/archaeological sites, and natural fragrances. Not all attributes are present at all Class I areas.

A non-steady state modeling approach which evaluates the effects of spatial changes in the meteorological and surface characteristics is necessary to properly evaluate the Class I Area impact analysis of the emissions sources. The EPA has adopted the CALPUFF[1] model system as a Guideline Model for Class I impact assessments and other long-range transport applications. CALPUFF is also recommended by the Federal Land Managers Air Quality Related Values Workgroup (FLAG, 2000) and the Interagency Workgroup on Air Quality Modeling (IWAQM, 1998) for these types of analyses.

The Class I Area air quality analysis shows that potential emissions from the proposed HU-Unit2 boiler will not cause or contribute to a violation of the PSD Class I Increments or AQRVs for the CCWA. See the Supplemental Class I Air Quality Modeling Analysis for the 750 MW Coal-Fired Boiler Hugo Unit 2 for details of the Class I Area impact analysis. Table VII-1 lists the modeled impacts.

[1] California Puff Model.

Table VII-1. SAIL Thresholds and Modeled Impacts

Pollutant	Year	Averaging Time	SAIL, µg/m^3	Modeled Impacts, µg/m^3
SO_2	2001	3-hour	1	1.57
		24-hour	0.2	0.32
		Annual	0.1	0.01
	2002	3-hour	1	1.32
		24-hour	0.2	0.40
		Annual	0.1	0.009
	2003	3-hour	1	1.21
		24-hour	0.2	0.22
		Annual	0.1	0.013
PM_{10}	2001	24-hour	0.3	0.14
		Annual	0.2	0.005
	2002	24-hour	0.3	0.16
		Annual	0.2	0.004
	2003	24-hour	0.3	0.04
		Annual	0.2	0.001
NO_X	2001	Annual	0.1*	0.009
	2002	Annual	0.1*	0.007
	2003	Annual	0.1*	0.009

* Value represents NO_2 SAIL level

As shown in the above table, the potential SO_2 emissions exceed their respective 3-hour and 24-hour SAILs; therefore, an additional increment analysis of PSD SO_2 increment consuming sources near the CCWA was performed. The additional increment analysis demonstrated that HU-Unit2 does not significantly contribute to a Class I increment exceedance for the CCWA. Details of the additional SO_2 increment analysis showing that HU-Unit2 does not contribute to a Class I SO_2 increment analysis can be found in the application's Supplemental Class I Air Quality Modeling Analysis and further revised air modeling (see Public Comments in Section XI).

<u>Visibility Analysis</u>

The project is not expected to produce any perceptible visibility impacts in the vicinity of the facility. EPA computer software for visibility impacts analyses, intended to predict distant impacts, terminates prematurely when attempts are made to determine close-in impacts. It is concluded that there will be no or minimal impairment of visibility resulting from the facility's emissions. Given the limitation of 20 percent opacity of emissions, and a reasonable expectation that normal operation will result in less than 20 percent opacity, no local visibility impairment is anticipated.

Growth Analysis

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the modification to the facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. Hugo Unit 2 is expected to increase employment in the area. The building phase will last approximately four years. Construction employment of approximately 1,000 workers is expected over the course of the construction period. Projected employment, reflecting full-time jobs directly tied to the operation of Hugo Unit 2, is estimated at 45 additional people at the facility. This will result in moderate amounts of secondary employment created by the economic activity of the facility.

Ambient Air Quality Analysis

The additional impacts analysis requires that all regulated pollutants be included in an ambient air quality analysis. The preceding sections describe the ambient air quality analysis conducted to demonstrate that emissions of NO_X, CO, SO_2, and PM_{10} from Hugo Unit 2 will result in ambient impacts less than the applicable NAAQS and PSD increments.

Soils & Vegetation Analyses

The potential effects of NO_2, SO_2, CO, and PM_{10} produced by the installation of Hugo Unit 2 on the nearby vegetation and soil were examined. The potential effects of the air emissions to vegetation within the immediate vicinity of Hugo Unit 2 were compared to scientific research examining the effects of pollution on vegetation. Damage to vegetation often results from acute exposure to pollution, but may also occur after prolonged or chronic exposures. Acute exposures are typically manifested by internal physical damage to leaf tissues, while chronic exposures are more associated with the inhibition of physiological processes such as photosynthesis, carbon allocation, and stomatal functioning.

Short- and long-term exposure to sulfur dioxide has been shown to have detrimental effects on many plant species. Symptoms of SO_2 injury in leaves manifest as interveinal necrotic blotches in angiosperms (plants having seeds enclosed within an ovary - flowering plants) and red brown banding in gymnosperms (plants having seeds not enclosed in an ovary). A number of the plant species studied occur in southeastern Oklahoma. These include red cedar (*Juniperus virginiana*), white oak (*Quercus alba*), sumac (*Rhus spp*.), white ash (*Fraxinus americana*), blackberry (*Rubus sp*.), American elm (*Ulmus americana*), soybean (*Glycine max*), corn (*Zea mays*), black willow (*Salix nigra*), and bracken fern (*Pteridium aquilinum*). Injury threshold concentrations varied by species and dose (131-5,240 $\mu g/m^3$ for 8 hours, 393-3,930 $\mu g/m^3$ for 2 hours, and 1,310 $\mu g/m^3$ for 4 hours). These concentrations are significantly higher than those expected to result from Hugo Unit 2 emissions. Even lichens and bryophytes, which are pollution bio-indicators due to their well-documented sensitivity to air pollution, would not be expected to be affected by long-term exposure to SO_2 emissions from Hugo Unit 2. They do not experience injury, decreased abundance, or lowered CO_2 uptake until SO_2 concentrations reach 5 to 40 $\mu g/m^3$ SO_2, 13 to 26 $\mu g/m^3$ SO_2, and 400 $\mu g/m^3$ SO_2 annually, respectively.

As with SO_2 emission research, NO_2 has been shown to deleteriously impact vegetation. Typical leaf injury responses include interveinal necrotic blotches similar to SO_2 injury for angiosperms and red-brown distal necrosis in gymnosperms. Injury threshold concentrations vary by species and dose, but are much higher than that of SO_2 as described above. In general, short-term high concentrations of NO_2 are required for deleterious impacts on plants. For example, a common, weedy plant found in Oklahoma, lamb's quarters (*Chenopodium album*), was not injured for two hours at concentrations 1.9 ug/m3 NO_2. Furthermore, short-term fumigations of approximately 1 hour, 20 hours, and 48 hours at NO_2 concentrations of 940 to 38,000 $\mu g/m^3$, 470 $\mu g/m^3$, and 3,000 to 5,000 $\mu g/m^3$, respectively, have been shown to deter photosynthesis in a number of herbaceous [tomato, oats (*Avena sativa*), alfalfa (*Medicago sativa*)] and woody plants. Moreover, in a review of NO_2 effects on vegetation, it was noted that long-term exposures of phytotoxic doses of NO_2 ranged from 280 to 560 $\mu g/m^3$. All the above concentrations are much greater than the average annual (0.41 $\mu g/m^3$) NO_2 emissions modeled to occur in the vicinity of the Hugo Generating Station.

Particulates may contain trace elements and heavy metals such as arsenic, boron, beryllium, copper, fluoride, nickel, lead, mercury, manganese, and cobalt. These compounds have been shown to be detrimental to vegetation typically within the immediate vicinity of the source. The most obvious effect of particle deposition on vegetation is a physical smothering of the leaf surface. This will reduce light transmission to the plant, in turn causing a decrease in photosynthesis. Modeling results have shown that PM_{10} increment is still available after the construction of Hugo Unit 2, and modeled values are almost one half less than the NAAQS level for 24-hour impacts including background. These levels are considered low, so it is highly unlikely that particulate matter emissions will impact vegetation adjacent to the Hugo Generating Station.

CO is not known to injure plants nor has it been shown to be taken up by plants. Consequently, no adverse impacts to vegetation at or near the Hugo Generating Station are expected from CO stack emissions.

Sulfates and nitrates caused by SO_2 and NO_2 deposition on soil can be beneficial and detrimental to soils depending on their composition. However, given the low expected deposition, the operation of Hugo Unit 2 should not significantly affect the soils on-site or in the immediate vicinity.

Based upon the results, it is concluded that the construction of Hugo Unit 2 will not have a significant adverse impact on the surrounding soil and vegetation.

Impacts on Threatened and Endangered Species

Although this is not a Federal permit and an analysis is not required, the applicant performed an impact analysis on federally protected species, details of which can be found in the application.

There are six federally protected species that are known or are likely to exist in Choctaw County. The new Hugo Unit 2 will be located at an existing coal-fired power plant site, so additional impacts at the site will be minimal. Most all of the identified protected species, except for the American burying beetle are associated with river bottom habitats and the plant site is situated on higher ground and will use existing cooling water sources. Since the site has already been disturbed with construction of Unit 1, the impact on the American burying beetle should also be minimal.

SECTION VIII. INSIGNIFICANT ACTIVITIES

The new insignificant activities identified and justified in the application are duplicated below. Appropriate recordkeeping of activities indicated below with a "*" is specified in the Specific Conditions.

1. * Stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for peaking power service not exceeding 500 hours per year. The facility includes an emergency generator used for emergency power generation and a diesel-powered fire water pump.

2. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBtu/hr heat input (commercial natural gas). None identified but may occur in the future.

3. Hand wiping and spraying of solvents from containers with less than 1 liter capacity used for spot cleaning and/or degreasing in ozone attainment areas. The facility performs small amounts of hand wiping and spraying of solvents. Solvent usage is conducted as a part of routine maintenance and is considered a trivial activity and recordkeeping will not be required in the Specific Conditions.

4. * Activities having the potential to emit no more than 5 TPY (actual) of any criteria pollutant. This includes the disposal of wastes generated from boiler cleaning, emergency engines, storage pile activities, and limestone handling activities. No others were identified but may occur in the future.

SECTION IX. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-4 (New Source Performance Standards) [Applicable]
Federal regulations in 40 CFR Part 60 are incorporated by reference as they exist on September 1, 2005, except for the following: Subpart A (Sections 60.4, 60.9, 60.10, and 60.16), Subpart B, Subpart C, Subpart Cb, Subpart Cc, Subpart Cd, Subpart AAA, Subpart BBBB, Subpart DDDD, Subpart HHHH, and Appendix G. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the AQD. Emission inventories were submitted and fees paid for previous years as required.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 7 includes the requirements for PSD Requirements for Attainment Areas. The Hugo Unit 2 project is considered a "Major Modification" at a "Major stationary source" since the existing facility exceeds 100 TPY of any criteria pollutant and the net emissions increase of criteria pollutants exceeds the significance thresholds. Part 7 is applicable to CO, NO_X, SO_2, PM_{10}, and H_2SO_4 mist for this project. As such, a BACT analysis (252:100-8-34), air quality impact analysis (252:100-8-35), and Class I area impact analysis (252:100-8-36) were required.
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

- 5 TPY of any one criteria pollutant, or
- 2 TPY of any one HAP or 5 TPY of multiple HAP or 20 percent of any threshold less than 10 TPY for single HAP that the EPA may establish by rule.

This facility meets the definition of a major source since it has the potential to emit regulated pollutants in excess of 100 TPY. As such, a Title V operating permit is required.

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release which results in excess emissions, the owner or operator of such facility shall notify the AQD as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility.

OAC 252:100-13 (Prohibition of Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies maximum allowable emissions of particulate matter (PM) based on rated heat input. All fuel-burning units are in compliance with their applicable limits.

Unit ID	Description	Equipment Capacity MMBtu/hr	Allowable Emission Rate lb/MMBtu	Emission Rate lb/MMBtu
HU-Unit2	HU-Unit2	7,125	0.11	0.025
HU-G, P-38	Diesel Fire Water Pump	3.4	0.60	0.34
HU-G, P-39	Emergency Diesel Generator	14.5	0.55	0.12
HU-SD, P-51	Wastewater Spray Dryer	20	0.51	0.01

This subchapter also specifies the allowable rates of emissions from industrial processes based on process rate. The following table lists the applicable processes, their process weight rate, and allowable emissions rate. As shown, all units are in compliance with their applicable emission limits.

Unit ID	Process	Process Rate (TPH)	Allowable Emission Rate (lb/hr)	Controlled Emission Rate (lb/hr)
HU-Coal1, P-3A	Rotary Car Dumper – Roof Dust Collector 1A	3,000	93	3.18×10^{-3}
HU-Coal1, P-3B	Rotary Car Dumper – Roof Dust Collector 1B	3,000	93	3.18×10^{-3}
HU-Coal1, P-3C	Rotary Car Dumper – Roof Dust Collector 1C	3,000	93	3.18×10^{-3}
HU-Coal1, P-3D	Rotary Car Dumper – Roof Dust Collector 1D	3,000	93	3.18×10^{-3}
HU-Coal1, P-3E	Rotary Car Dumper – Bottom Dust Collector 2	4,200	98	4.45×10^{-3}
HU-Coal2, P-4A	Transfer House - Dust Collector 3	3,000	93	0.07
HU-Coal2, P-4B	Coal Silo A – Roof Dust Collector 4	3,000	93	0.07
HU-Coal7, P-25	Coal Silo B – Roof Dust Collector 4A	3,000	93	0.07
HU-Coal2, P-4C	Coal Silo A – Bottom Dust Collector 5	4,800	100	0.11
HU-Coal7, P-26	Coal Silo B – Bottom Dust Collector 5A	2,400	89	0.05
HU-Coal3, P-5A	Crusher House – Dust Collector 6	2,400	89	0.05

Unit ID	Process	Process Rate (TPH)	Allowable Emission Rate (lb/hr)	Controlled Emission Rate (lb/hr)
HU-Coal3, P-5B	Hugo Unit 1 Coal Silos – Dust Collector 7	2,400	89	0.05
HU-Coal8, P-27	Hugo Unit 2 Coal Silos – Dust Collector 8	2,400	89	0.05
HU-Coal5, P-7A	Reclaim Hopper No. 1 – aboveground	1,200	80	0.06
HU-Coal5, P-7B	Reclaim Hopper No. 2 – underground	1,200	80	0.02
HU-Coal5, P-7C	Reclaim Hopper No. 2 – aboveground	1,200	80	0.06
HU-Coal5, P-7D	Reclaim Hopper No. 3 – aboveground	2,400	89	0.13
HU-Coal9, P-28	Chain Reclaim (drop to reclaim hopper)	2,400	89	0.13
HU-Coal9, P-29	Chain Reclaim (drop to conveyor R-1)	2,400	89	0.13
HU-Ash6, P-30	Hugo Unit 2 Fly Ash Silo Bin Vent #1	62.5	47	0.58
HU-Ash6, P-31	Hugo Unit 2 Fly Ash Silo Bin Vent #2	62.5	47	0.58
HU-Ash7, P-32	Hugo Unit 2 Fly Ash Silo Loading to Trucks	99.8	51	0.06
HU-Ash8, P-33	Fly Ash Storage Building – Dust Collector 1	62.5	47	0.58
HU-Ash8, P-34	Fly Ash Storage Building – Dust Collector 2	62.5	47	0.58
HU-Ash9, P-35	Fly Ash Rail Loadout	100	51	0.06
HU-Ash10, P-36	Fly Ash Rail Bin Vent #1	62.5	47	0.58
HU-Ash10, P-37	Fly Ash Rail Bin Vent #2	62.5	47	0.58
HU-LS1, P-47	Limestone Receiving Hopper	600	71	3.1×10^{-3}
HU-LS2, P-48	Limestone Reclaim Tunnel	400	66	0.01
HU-LS3, P-49	Limestone Silo 1	400	66	0.01
HU-LS4, P-50	Limestone Silo 2	400	66	0.01

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20 percent opacity is allowed except for short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60 percent opacity. Units subject to an opacity standard under NSPS are exempt from this subchapter. Therefore, the new and existing large boilers and coal handling activities are exempt from this subchapter. The auxiliary boiler (HU-Aux), the wastewater spray drier (HU-SD), the ash handling activities, and the limestone handling activities are subject to this requirement and visible emissions observations for these emission points are required by the permit.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Fugitive dust emissions that could be caused by coal and fly ash handling and storage are minimized by extensive use of fabric filters, closed systems and other measures. Confining the active disturbance to a very small area minimizes fugitives from the coal piles. This permit also requires that reasonable precautions be taken to minimize fugitive dust.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For solid fuels, the limit is 1.2 lb/MMBtu. Emission rates are in compliance with the limitations of Subchapter 31. For liquid fuels, the limit is 0.8 lb/MMBtu. The permit will require the use of No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight.
Part 5 also requires opacity and sulfur dioxide monitoring for new fuel-burning equipment rated above 250 MMBtu/hr. The new 750 MW boiler (HU-Unit2) is rated at 7,125 MMBtu/hr. Opacity and SO_2 monitors will be installed to continuously monitor emissions from HU-Unit2.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits new solid fossil fuel-burning equipment with rated heat input greater than or equal to 50 MMBtu/hr to emissions of 0.7 lb of NO_X per MMBtu. The permit will limit NO_X emissions from the HU-Unit2 boiler to 0.07 lb/MMBtu for a 30-day rolling average. For liquid-fired fuel-burning equipment, the limit is 0.3 lb/MMBtu. The emergency engines are all smaller than the 50 MMBtu/hr threshold and are not subject to this subchapter.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The storage tanks at the facility are exempt from this part since they store a VOC with a vapor pressure less than 1.5 psia.
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity greater than 40,000 gallons to be equipped with a floating roof or a vapor-recovery system capable of collecting 85% or more of the uncontrolled VOC emissions. The fuel oil storage tank at the facility is exempt from this part since it stores a VOC with a vapor pressure less than 1.5 psia.

Part 3 requires loading facilities with a throughput equal to or less than 40,000 gallons per day to be equipped with a system for submerged filling of tank trucks or trailers if the capacity of the vehicle is greater than 200 gallons. The facility has gasoline loading operations, but only for filling vehicles with tanks less than 200 gallons; therefore, Part 3 is not applicable.
Part 5 limits the VOC solvent content of coating or other operations. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires all effluent water separator openings or floating roofs to be sealed or equipped with an organic vapor recovery system. The effluent water separator located at the facility receives insignificant amounts of oil throughput (< 200 gal/day of VOC) and is, therefore, not subject to this requirement.
Part 7 requires all reciprocating pumps and compressors handling VOCs to be equipped with packing glands that are properly installed and maintained in good working order and all rotating pumps and compressors handling VOCs to be equipped with mechanical seals. There are no pumps or compressors handling VOCs on-site.
Part 7 requires fuel-burning equipment to be operated and maintained to minimize emissions. Temperature and available air must be sufficient to provide essentially complete combustion. All fuel burning equipment at this facility is subject to this requirement.

OAC 252:100-41 (Hazardous Air Pollutants (HAP)) [Applicable]
Part 3 addresses hazardous air contaminants. NESHAP, as found in 40 CFR Part 61, are adopted by reference as they exist on September 1, 2005, with the exception of Subparts B, H, I, K, Q, R, T, W and Appendices D and E, all of which address radionuclides. In addition, General Provisions as found in 40 CFR Part 63, Subpart A, and the Maximum Achievable Control Technology (MACT) standards as found in 40 CFR Part 63, Subparts F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, MM, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, QQQ, RRR, TTT, UUU, VVV, XXX, AAAA, CCCC, DDDD, EEEE, FFFF, GGGG, HHHH, IIII, JJJJ, KKKK, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, VVVV, WWWW, XXXX, YYYY, ZZZZ, AAAAA, BBBBB, CCCCC, EEEEE, FFFFF, GGGGG, HHHHH, IIIII, JJJJJ, KKKKK, LLLLL, MMMMM, NNNNN, PPPPP, QQQQQ, RRRRR, SSSSS and TTTTT are hereby adopted by reference as they exist on September 1, 2005. These standards apply to both existing and new sources of HAPs. These requirements are covered in the "Federal Regulations" section.
Part 5 was a **state-only** requirement governing sources of toxic air contaminants that have emissions exceeding a *de minimis* level. However, Part 5 of Subchapter 41 has been superseded by OAC 252:100-42, effective June 15, 2006.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Part 5 of OAC 252:100-41 was superceded by this subchapter. Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-7	Permits for Minor Sources	not in source category
OAC 252:100-11	Alternative Emissions	not requested
OAC 252:100-15	Motor Vehicle Pollution Control	not in source category
OAC 252:100-17	Incinerators	not in source category
OAC 252:100-21	PM Emissions From Wood-Waste Burning Equipment	not in source category
OAC 252:100-23	Control of Emissions From Cotton Gins	not type of emission unit
OAC 252:100-24	PM Emissions from Grain, Feed or Seed Operations	not in source category
OAC 252:100-35	Control of Emission of Carbon Monoxide	not in source category
OAC 252:100-39	Emission of VOCs in Nonattainment Areas and Former Nonattainment Areas	not in special control/Nonattainment Area
OAC 252:100-47	Control of Emissions from Existing Municipal Solid Waste	not in source category

SECTION X. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
Potential emissions for NO_X, CO, VOC, PM_{10}, SO_2, and H_2SO_4 mist are greater than the level of significant emission rates for this source category. Full PSD review was conducted in accordance with Part 7 of OAC 252:100-8.

NSPS, 40 CFR Part 60 [Subparts Da and Y are Applicable]
Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This subpart regulates EGUs capable of combusting more than 250 MMBtu/hr heat input of fossil fuel and was amended on February 27, 2006. The new standards for EGU burning solid fossil fuel and constructed after February 28, 2005 are listed below:

PM:	(1) emit no more than either 0.14 lb/MWh (gross output, equivalent to 0.017 lb/MMBtu for HU-Unit2) or 0.015 lb/MMBtu (input) or (2) emit no more than 0.03 lb/MMBtu (input) and 0.1 percent of the potential combustion concentration (CRF 60.42Da)
Opacity:	20 percent except for one six-minute period per hour of not more than 27 percent (40 CFR 60.42Da)
SO_2:	1.4 lb/MWh (gross output, equivalent to 0.17 lb/MMBtu for HU-Unit2) or 5 percent of the potential combustion concentration (95 percent removal) on a 30-day rolling average (40 CFR 60.43Da)
NO_X	1.0 lb/MWh (gross output, equivalent to 0.12 lb/MMBtu for HU-Unit2) on a 30-day rolling average (40 CFR 60.44Da)

HU-Unit2 will have emissions limitations at or below these required limits.

Subpart Da requires that each owner or operator install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMs) for measuring the opacity, PM (either CEMs or system of bag leak detectors), sulfur dioxide, nitrogen oxides, mercury emissions, and either oxygen or carbon dioxide (40 CFR 60.49Da). Performance test methods and procedures (40 CFR 60.50Da) and reporting requirements (40 CFR 60.51Da) are also specified.

Under the CAMR, mercury standards of performance are established based on gross electrical output and are listed for new coal-fired units in Subpart Da. For units combusting subbituminous coal scrubbed with a wet scrubber, the limit was originally set at 42×10^{-6} lb/gross MW-hr. On October 28, 2005, EPA issued notice of its reconsideration of the CAMR. EPA has tentatively concluded that the appropriate mercury emission limit for wet subbituminous coal plants, such as the Hugo Generating Station, is 66×10^{-6} lb/MWhr. As stated in the October 28th Federal Register notice (70 F.R. 62213, 62216), the technologies which are most effective in reducing mercury emission are those installed to comply with current NSPS standards for PM_{10} and SO_2 (i.e., fabric filter and wet FGD). Based on EPA's analysis and reconsideration of the CAMR, EPA has proposed a mercury emission limit of 66×10^{-6} lb/MWhr. The permit establishes a mercury emission limit of 66×10^{-6} lb/MWhr. The DEQ is reserving the right to reopen the permit, if necessary, and administratively amend the mercury emission limit to specify the final mercury CAMR limit once promulgated by EPA.

Subpart Y, Standards of Performance for Coal Preparation Plants. Subpart Y applies to coal preparation plants constructed or modified after October 24, 1974, with a capacity greater than 200 TPD. Affected sources include thermal dryers, pneumatic coal-cleaning equipment, coal processing, and conveying equipment (including breakers and crushers), coal storage systems (exclusive of open storage piles), and coal transfer and loading systems. All equipment at this facility was constructed after the specified date and the individual unit capacities exceed 200 TPD. The facility does not have thermal dryers or pneumatic cleaning equipment. The following standard must be met by the facility:

> Opacity from any coal processing and conveying equipment, coal storage system, and coal transfer and loading systems shall be below 20 percent opacity (40 CFR 60.252).

Subpart Y requires that Reference Method 9 be used to demonstrate compliance with the opacity standard (40 CFR 60.254). The facility uses fabric filters to control PM emissions from the coal unloading, and the coal is conveyed in closed systems. The facility will comply with this subpart.

NESHAP, 40 CFR Part 63 [Not Applicable]
On March 29, 2005, EPA issued a final rule removing coal-fired and oil-fired utility boilers from the source category list in Section 112(c) based on a determination that it was neither appropriate nor necessary to regulate such units under Section 112 (i.e. Air Quality and Emissions Standards for Hazardous Air Pollutants (HAPs)). This reversed a December 2000 determination by EPA that concluded that utility mercury emissions for coal-fired and oil-fired utility units should be regulated under Section 112 (d). In lieu of that regulatory approach, EPA implemented mercury regulations through the CAMR addressed in NSPS Subpart Da. On October 28, 2005, the EPA announced reconsideration of parts of the March 29, 2005 action and solicited public comments on those limited parts (this is the same FR notice that proposed revision of the CAMR standards for mercury). Based on EPA actions, a case-by-case MACT analysis is no longer required for new utility units and no federal MACT standard is in effect for mercury emissions from coal-fired and oil-fired boilers.

CAM, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant of 100 TPY of a criteria pollutant, 10 TPY of an individual HAP, or 25 TPY of total HAP

CAM requirements do not apply to (1) emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 (NSPS) or 112 (NESHAP); (2) Acid Rain Program requirements; or (3) emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method.

Therefore, for the pollutants with limitations for HU- Unit2, CAM does not apply to emissions of NO_X and SO_2 (subject to standards in NSPS Subpart Da and Acid Rain Program), emissions of

PM_{10} and Hg (subject to standards in NSPS Subpart Da), emissions of CO and VOC (no control device), emissions of H_2SO_4 Mist (not a HAP), and emissions of lead and beryllium (emissions prior to the control device of less than 10 TPY). Potential emissions of fluorides (as HF) are 14 TPY; therefore, CAM is applicable. PM emissions from the limestone handling activities have pre-control emissions of less than 100 TPY. PM emissions from most of the coal and ash handling activities have pre-control emissions of more than 100 TPY, but post-control emissions less than 100 TPY. Therefore, a CAM plan for the control of fluorides and for the control devices (bag filters) on the coal and ash handling systems is required, but not until an application is made for renewal of the Part 70 permit.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable]
This facility does not store any regulated substance above the applicable threshold limits. More information on this federal program is available at the web site: *http://www.epa.gov/ceppo/*. An analysis will be done after the design of Hugo Unit 2 is finalized to determine if the Hugo Generating Station will store any of the listed chemicals or substances at quantities near or above the threshold levels.

Acid Rain Program, 40 CFR Part 72 (Permit Requirements) [Applicable]
The Acid Rain requirements under Part 72 are applicable to HU-Unit2. An Acid Rain permit application under Title IV shall be completed and an Acid Rain permit shall be obtained under these regulations.

Acid Rain Program, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
SO_2 allowances shall be obtained for this facility. All allowances can be traded, bought, and sold. Therefore, the actual allowances held by an affected unit may change which will not necessitate a revision to the permit.

Acid Rain Program, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
Certification testing shall be completed for the CEM systems required (SO_2, NO_X, either O_2 or CO_2, and opacity) for the HU-Unit2. Appendix F of Part 75 outlines the procedures for calculating emissions of SO_2 and NO_X from CEMs data and procedures to calculate the total heat input (based on Gross Caloric Value of the coal) to arrive at emissions expressed as lb/MMBtu.

Acid Rain Program, 40 CFR Part 76 (NO_X Emission Reduction Program) [Applicable]
40 CFR Part 76 establishes NO_X emission limitations for coal-fired EGUs. The new 750 MW boiler (HU-Unit2) is subject to a more stringent limitation based on BACT requirements of PSD.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subpart A and F Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon

disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

This facility does not utilize any Class I & II substances.

SECTION XI. COMPLIANCE

Tier Classification and Public Review

This application has been determined to be a Tier II based on the request for a construction permit for a significant modification to an existing major source.

The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the real property.

The applicant published the DEQ "Notice of Filing a Tier II Application" in the *Hugo Daily News*, a daily newspaper in the City of Hugo, Choctaw County, on September 30, 2005. The notice stated that the application was available for public review at the Choctaw County DEQ Office, 502 W. Duke Street, Hugo, Oklahoma. A draft of this permit, and a copy of the revised application, was made available for public review for a period of 30 days as stated in the "Tier II Notice of Draft Permit" which was published in the *Hugo Daily News* on June 30, 2006. The notice also informed the public of a public meeting regarding the draft permit which was held on August 1, 2006 at 6:00 p.m. at the Kiamichi Vocational Technology Center in Hugo, Oklahoma. Public comments were received as discussed below. The applicant had requested concurrent public and EPA review. However, since public comments were received, the draft permit cannot be considered the "proposed" permit and the "proposed" permit was sent to EPA Region VI for a new 45-day review period. No comments were received from the EPA.

This facility is within 50 miles of the Oklahoma border with Arkansas and Texas; those states were notified of the availability of the draft permit. Comments were received from the state of Arkansas as discussed below.

All Tier II permit drafts are also available for public review in the Air Quality section of the DEQ web page: //www.deq.state.ok.us/.

Public Comments

Public comments were received from three entities during the public comment period: (1) Mr. Norman L. Wagoner, Forest Supervisor, Ouachita National Forest, in his capacity as the Federal Land Manager (FLM) for the Caney Creek Wilderness Area (CCWA); (2) Mr. Brian Bond, VP External Affairs, Southwestern Electric Power Company (SWEPCO); and (3) Mr. Marcus C. Devine, Director, Arkansas Department of Environmental Quality (ADEQ). No one from the public attended the public meeting that was held on Tuesday, August 1, 2006 at 6:00 p.m. at the Kiamichi Vocational Technology Center in Hugo, Oklahoma; therefore, no public comments were received at that meeting. The public comment period was not extended and it ended at the end of the public meeting.

Comments from the FLM for the CCWA

Comments were received on July 24, 2006 from the FLM and contained both "findings" and "recommendations". For accuracy and to avoid confusion, the FLM comments are listed verbatim with the Air Quality Divisions (AQD) response inserted after each comment.

A. Findings

Based on the information provided by the applicant in the PSD application and supporting technical studies, our office has reached the following findings with regard to the impacts of the proposed Hugo Unit #2 project on air quality-related values at the Caney Creek Wilderness.

1. The applicant's modeling analysis has predicted violations of the Class I increment for sulfur dioxide (SO_2) at the Caney Creek Wilderness. For the 24-hour average, the maximum increment consumption is predicted to be 15.75 micrograms per cubic meter, a level which is more than three times the allowable increment of 5 micrograms per cubic meter. PSD increment violations are also predicted at Caney Creek for the 3-hour averaging time.

   AQD Response No. 1

   Several FLM comments related to the exceedance of the Class I increment for SO_2 that was shown by Class I modeling performed by the applicant. Comments from SWEPCO and ADEQ are in regard to the same issue and both of their comments suggest that the SO_2 increment is not exceeded for various reasons. Therefore, all comments regarding exceedance of SO_2 increment at CCWA are covered in the section below entitled "Class I SO_2 Increment Consumption and Revised Air Modeling".

2. The applicant claims that Unit #2 will not "significantly" contribute to any of the predicted PSD increment violations at Caney Creek (based on the modeled SO_2 emissions rate of 0.065 lb/MMBtu). The maximum predicted 24-hour average SO_2 increment consumption (paired in time and space with the predicted increment violations at Caney Creek) is 0.18 micrograms per cubic meter. The significant impact level (SIL) used for SO_2 24-hour average PSD increment consumption is 0.2 micrograms per cubic meter.

   <u>AQD Response No. 2</u>

   Based on Class I air modeling for the application and subsequent modeling, the impact from the proposed Hugo Unit 2 does not exceed any SAIL for SO_2 at the receptors when a violation of the increment was predicted at those receptors. Since the impact from Hugo Unit 2 does not exceed the SAIL at the receptors when and where a violation was predicted, AQD has determined that construction of the proposed Hugo Unit 2 will not cause or contribute to SO_2 increment consumption at the CCWA. However, even if a proposed source does not cause or contribute to a violation of a Class I increment, the FLM may demonstrate to the satisfaction of the Administrator (AQD) that the source will have an adverse impact on air quality related values (AQRV). AQD must consider the FLM analysis and if the agency determines that an adverse impact is demonstrated, the permit cannot be issued.

3. Although the applicant's modeling claims that Hugo Unit #2 does not "significantly" contribute to any of the predicted PSD increment violation at Caney Creek, our review indicates that Hugo Unit #1 emissions probably "significantly" contribute to the predicted PSD violations. Our conclusion is based on the Unit #1 increment-consuming SO_2 emissions reported in the application (2,651 lb/hr) and the reported impacts for Unit #2.

   <u>AQD Response No. 3</u>

   There is no federal or Oklahoma regulatory basis for singling out Hugo Unit 1 as causing or contributing to a violation of increment consumption at CCWA since there are many increment consuming major sources involved. If the PSD increment has been violated, then Region VI, the state of Oklahoma, the state of Arkansas, and possibly the state of Texas, would be responsible to do additional research and air modeling to determine the sources that contribute to the violation and take appropriate corrective measures.

4. Following the FLAG modeling procedures, Hugo Unit #2 is predicted to have an impact on visibility greater than 10% change in extinction on approximately one day in three years. A potential visibility impact above 10% is of concern to this office.

AQD Response No. 4

In accordance with 40 CFR 52.21(p)(1) and OAC 252:100-8-36(b)(2), AQD notified the FLM within 30 days of receipt of this permit application and submitted a copy of the application and Class I impact analysis. According to 40 CFR 52.21(p)(3) and OAC 252:100-8-36(c), AQD shall consider an analysis performed by the FLM (that shows that a proposed new major stationary source or major modification may have an adverse impact on visibility in any Federal Class I area) provided that the analysis is filed with the DEQ within 30 days of receipt of the application by the FLM. Where the Director finds that such an analysis does not demonstrate to the satisfaction of the Director that an adverse impact on visibility will result in the Federal Class I area, the Director will, in any notice of public hearing on the permit application, either explain the decision or give notice as to where the explanation can be obtained.

Protection of Class I areas is of concern to AQD and the comment of the FLM expressing concern on visibility impacts was considered to insure that the Class I area is protected. Through the use of different methods approved by the FLM, the applicant was able to show that there was not a potential impact on visibility greater than 10%. Based on these analyses, AQD does not feel that there is an adverse impact on AQRV at the CCWA.

5. Review of the existing Interagency Monitoring of Protected Visual Environments (IMPROVE) aerosol monitoring data collected at Caney Creek suggests that existing visibility is currently impaired and that the worst-case visibility days are often associated with emissions transport from the south and southwest of Caney Creek. Hugo Unit #2 would be located in this direction from Caney Creek. Our office believes that the proposed Unit #2 emissions would add to the regional pollutant burden that already impairs existing visibility conditions at Caney Creek Wilderness.

AQD Response No. 5

See AQD Response No. 4. Also, AQD considers this comment as too broad and without enough specific information for AQD to determine that the proposed Hugo Unit 2 will contribute to an adverse impact on AQRV at the CCWA.

6. The predicted sulfur deposition at Caney Creek from the Hugo Unit #2 emissions is approximately equal to the established SIL of 0.01 kg/ha-yr.

AQD Response No. 6.

According to guidance issued by the National Park Service and the U.S. Fish and Wildlife Service, the Deposition Analyses Threshold (DAT) of 0.01 kg/ha-yr is a deposition threshold, not necessarily an adverse impact threshold. The DAT is the additional amount of deposition that triggers a management concern, not necessarily the amount that constitutes an adverse impact to the environment. Therefore, AQD considers the comment that sulfur deposition is approximately equal to the DAT as an expression of management concern, but not as a comment that an adverse impact on AQRV has been demonstrated.

B. Recommendations

Our findings discussed above indicate that the proposed Hugo Unit #2, based on information we have at this time will have potential impacts to the Caney Creek Wilderness as well as possibly exacerbate already existing impacts to PSD increment consumption and air quality-related values at Caney Creek. We have determined that such impacts should be mitigated before our office can support the issuance of a PSD permit for the proposed Hugo Unit #2 project. Specific recommendations on how to address these issues follow below.

1. The accuracy of the SO_2 increment consuming inventory used by the applicant needs to be reviewed and confirmed. Our office is alarmed that the applicant's modeling analysis shows that the SO_2 PSD increment is consumed at Caney Creek and is in fact exceeded by more than a factor of three on the "worst-case" day. If the PSD increment consumption analysis is confirmed, corrective action will be needed to bring the Caney Creek PSD increment levels into compliance, although we recognize that any such corrective actions may need to occur outside the scope of the Hugo Unit #2 PSD permit. Since protecting PSD increment at Caney Creek falls under the jurisdiction of the State of Arkansas, any such efforts should be coordinated with both Arkansas and USEPA Region VI. Our office would also appreciate periodic updates on the progress of any efforts to confirm and if necessary remedy the Class I increment violations predicted at Caney Creek by the applicant's modeling.

   <u>AQD Response No. 7</u>

   See AQD Response No. 1. Based on the FLM comments and the SWEPCO and ADEQ comments, AQD agreed that further air modeling with more accurate emission data was warranted. Results from revised air modeling are covered in the section below entitled "<u>Class I SO_2 Increment Consumption and Revised Air Modeling</u>".

2. The permit review should closely scrutinize the applicant's Best Available Control Technology (BACT) analysis to ensure that emissions and the associated impacts from Hugo Unit #2 on the Caney Creek Wilderness are minimized. Given the importance of the air quality-related values at Caney Creek and the level of impact predicted by the applicant's modeling, additional weight should be placed on the possible environmental benefits of higher levels of pollution control when balancing the energy, environmental, and economic factors as required under BACT. As noted in the permit analysis, the proposed BACT control for SO_2 emissions represents approximately 96% sulfur removal. Consideration should be given to setting the BACT emissions level at greater than 96% sulfur removal given the magnitude of the Hugo Unit #2 impacts to the Caney Creek Wilderness.

AQD Response No. 8

AQD has determined that the BACT limit for SO_2 emissions is appropriate. The limit is one of the two lowest BACT limits for SO_2 ever permitted in the United States for a new coal boiler and represents the applicant's use of low sulfur coal in conjunction with a modern wet gas scrubber. Although SO_2 removal efficiencies slightly higher than 96% can be achieved, they are typically associated with higher sulfur loadings in the flue gas and the resultant overall SO_2 BACT limit is higher than the limit of 0.065 lb/MMBtu for Hugo Unit 2.

3. Our review of the Class I modeling analysis indicates that the proposed BACT SO_2 emissions limit (0.065 lb/MMBtu) was modeled in CALPUFF to assess impacts to the Caney Creek Wilderness. However, a higher 24-hour average SO_2 limit of 0.10 lb/MMBtu has been proposed in the draft permit. To our knowledge, the higher SO_2 emission limit has not been evaluated in the modeling of possible visibility and increment consumption at the Caney Creek Wilderness. For increment, the analysis of 3-hour and 24-hour impacts needs to be based on the proposed 24-hour SO_2 emission rate and not the proposed 30-day rolling emissions limit. Correcting the Class I impacts for this change in emissions would raise the modeled impacts from Hugo Unit #2 by about 50%. If the higher SO_2 emissions were correctly modeled, our analysis suggests that the applicants "contribution" to modeled Class I PSD increment exceedances at Caney Creek would increase to above the established significant impact levels for Class I areas (our office projects a maximum 24-hour contribution from Hugo Unit #2 of 0.27 micrograms per cubic meter). The visibility impacts (which already exceed the 10% threshold used by our office to evaluate the potential impacts of a project) would also increase. Given these findings, the proposed PSD permit for Hugo Unit #2 cannot be issued as written. Either a proper analysis of PSD increment and visibility impacts is needed based on the proposed 24-hour average SO_2 emission rate or the proposed BACT limit (0.065 lb/MMBtu) needs to be established based on a maximum 24-hour average.

AQD Response No. 9

A lb/hr emissions rate is used for modeling purposes. The probability of Hugo Unit 2 operating at maximum load and emitting more than a rate of 0.065 lb/MMBtu at the same time as weather conditions would cause Hugo Unit 2 to have a significant impact on the CCWA is very remote. However, to help alleviate some of the FLM concerns about the emissions rate used for modeling purposes, AQD will add a 24-hour rolling total limit on SO_2 emissions that is equivalent to the boiler operating at maximum heat input at the BACT limit of 0.065 lb/MMBtu. The limit will be 463 lb of SO_2 emitted in any rolling 24-hour period.

4. Notwithstanding the issues raised above, the predicted impacts of the proposed Hugo Unit #2 project need to be mitigated before a PSD permit for this project is issued. The analysis of impacts required under the PSD permit have documented that

cumulative impacts to PSD increment consumption and air quality-related values are currently occurring at Caney Creek and that the applicant's existing Unit #1 (and perhaps also Unit #2) contributes to these impacts (including PSD increment consumption). For mitigation, our office recommends adopting an approach used in similar PSD permitting efforts in West Virginia, although we are also open to other suggestions. Under the proposed approach, the Hugo Unit #2 PSD permit would require that the applicant secure "excess" SO_2 emission allowances equal to the proposed Unit #2 SO_2 emissions. In addition, the PSD permit should provide incentives to the applicant to secure the necessary allowances from SO_2 emission sources in close proximity to Caney Creek, so that any emissions reductions would directly benefit air quality-related values at Caney Creek. To that end, our office recommends a 2-to-1 allowance ratio be set in the PSD permit when the SO_2 allowance is secured from emission sources within 200 km of Caney Creek. However, a 4-to-1 allowance ratio should be required when the SO_2 allowance is secured from emission sources located more than 200 km from Caney Creek. Please note that the proposed mitigation is in addition to any mitigation required to address the Hugo Unit #2 impacts at the proposed 24-hour SO_2 emission limit of 0.10 lb/MMBtu, which have not been adequately addressed in the permit review. We would also be interested in discussing any other ideas for impact mitigation that might be proposed either by your office or the applicant.

AQD Response No. 10

See AQD Response No. 3. Allowing a proposed source to mitigate the adverse impacts that source may have on a Class I Area is a valid option so that a source that has an adverse impact may still obtain a PSD permit. However, in this case, it has not been demonstrated that the proposed source (Hugo Unit 2) has an adverse impact on the CCWA. Therefore, the proposed source is not required, nor does AQD have the authority to require the proposed source, to buy "excess" SO_2 allowances to mitigate an adverse impact for which the applicant's existing source (Hugo Unit 1) and any number of other existing sources may be contributing to.

Comments from SWEPCO

Comments from SWEPCO were received on August 1, 2006. SWEPCO made several general comments on the air modeling performed to determine impacts on the CCWA. In general, SWEPCO commented that the WFEC analyses included overly conservative assumptions and data inconsistencies, which should be considered as possible contributors to the reported allowable increment exceedances. Specifically, SWEPCO commented that the stack locations for the Domtar Industries, Inc., Eastman Chemical, and Independence Power Plant sources were modeled more than 100 kilometers from their actual locations. Also, SWEPCO commented that SO_2 emissions from some Arkansas PSD sources that were constructed prior to the January 6, 1975 baseline date may have been included in the modeling and that the modeling may not have taken into consideration SO_2 emission rate reductions at some of those facilities that have occurred since that date.

AQD Response No. 11

See AQD Response No. 1.

Comments from the ADEQ

The ADEQ commented that their review of the of the Class I air modeling indicated that sources modeled as increment consuming should instead be considered as part of the baseline and that other major sources which may be increment consuming appeared to be modeled with wrong coordinates of with allowable instead of actual emissions. ADEQ commented that their review confirms that the Caney Creek Wilderness is not part of the "baseline area" of any major source in Arkansas and that, therefore, the minor source baseline date has not been triggered for the Caney Creek Wilderness.

AQD Response No. 12

See AQD Response No. 1.

Class I SO_2 Increment Consumption and Revised Air Modeling

The most significant public comments on the draft permit were in regard to the Class I air modeling results which showed that the SO_2 increment for the CCWA had been exceeded. AQD agreed that the air modeling contained some inconsistent data for the stack location of several increment consuming PSD major sources and for the sources and emission rates modeled. The AQD did not agree fully with the ADEQ comments regarding the emission rates used at some of the increment consuming sources. Since 3-hour and 24-hour averaging periods are at issue, it is not always possible to know or get data on actual emissions for those averaging periods from those sources; therefore, AQD agrees with the original assumptions of the applicant to use potential to emit rates in those cases. Also, it was not clear to AQD based on the comments from ADEQ whether or not the minor source baseline date has been triggered for the CCWA.

Gathering detailed emission source information necessary to make a determination on baseline trigger dates and increases and decreases in emissions from increment consuming PSD sources can take a considerable amount of time. However, AQD and WFEC felt that the Class I air modeling should be updated based on more exact data in order to be sure that there are times when the SO_2 increment is exceeded at the CCWA and to be sure that the proposed Hugo Unit 2 does not make a significant contribution to those times of exceedance. WFEC revised the SO_2 increment inventory using information obtained with the aid of AQD staff, ADEQ staff, and the EPA acid rain database. Consistent with earlier data and modeling, the revised air modeling showed exceedance of the 3-hour and 24-hour Class I increment at the CCWA. However, also consistent with the earlier modeling, the revised modeling confirmed that emissions from the proposed Hugo Unit 2 will not be a significant contributor to the modeled 3-hour and 24-hour SO_2 increment exceedance at the CCWA.

WFEC Hugo Unit 2 Class I SO_2 Increment Analysis (11/06 Revision)			
Year	Number of Days Total Model Impacts Exceed SO_2 Class I Increment	Number of Receptors that Exceed SO_2 Class I Increment	Unit 2 Exceed Significance Threshold for Receptors Exceeding SO_2 Class I Increment?
3-Hour			
2001	12	318	No
2002	14	499	No
2003	2	132	No
24-Hour			
2001	25	1049	No
2002	25	1236	No
2003	17	720	No

All air modeling (the original application, the supplemental air modeling, and the revised air modeling) shows no significant contribution from the proposed Hugo Unit 2 on the modeled exceedance of SO_2 increment at the CCWA.

Fees Paid

A fee of $1,500 for a construction permit for a major source has been paid.

Administrative Amendments

AQD corrected a few errors in Table V.II. The Sandy Creek CO limit should have been 0.15 not 0.015 lb/MMBtu. The Nebraska City Unit 2 CO limit should have been 0.16 not 0.016 lb/MMBtu. The Comanche Generating Station H_2SO_4 limit should have been 0.0042 not 0.0029 lb/MMBtu. The TS Power Plant PM_{10} limit should have been 0.012 not 0.038 lb/MMBtu.

AQD also corrected some errors in the first paragraph of page 65 of the memorandum dealing with the SIA for PM and SO_2 emissions. The wording in the draft and proposed permit was:

"There are two steps required to determine which facilities qualify as "nearby facilities." First, the region in which all sources must be initially classified as "nearby sources" must be defined. This region extends to 50 kilometers beyond the largest pollutant-specific SIA. A pollutant-specific SIA is the region within which the pollutant impacts are expected to exceed the SAIL. In this case, the PM_{10} SIA extends approximately 5 kilometers from the center of the facility, and SO_2 impacts extend 115 kilometers from the center of the facility (values determined from dispersion modeling). All facilities that emit the pollutant for which the full analysis is being performed and that fall within a 50 kilometer radius of the pollutant-specific SIA are to be considered for inclusion in the modeling analysis. Therefore, for this analysis, all sources of PM_{10} within 150 kilometers of the facility and SO_2 sources within 150 kilometers are to be considered nearby sources unless they are otherwise disqualified. NO_X and CO emissions do not exceed the SAIL level; therefore an SIA is not triggered." This was changed to:

"There are two steps required to determine which facilities qualify as "nearby facilities." First, the region in which all sources must be initially classified as "nearby sources" must be defined. This region extends to 50 kilometers (km) beyond the largest pollutant-specific SIA. A pollutant-specific SIA is the region within which the pollutant impacts are expected to exceed the SAIL. In this case, the PM_{10} SIA extends approximately 5 km from the center of the facility, and SO_2 impacts extend 18.3 km (3 hr averaging period) and 8.0 km (24 hr averaging period) from the center of the facility (values determined from dispersion modeling). All facilities that emit the pollutant for which the full analysis is being performed and that fall within a 50 km radius of the pollutant-specific SIA are to be considered for inclusion in the modeling analysis. Therefore, for this analysis, all sources of PM_{10} within 55 km of the facility and SO_2 sources within 70 km are to be considered nearby sources unless they are otherwise disqualified. NO_X and CO emissions do not exceed the SAIL level; therefore an SIA is not triggered."

SECTION XII. SUMMARY

AQD sent a copy of the "proposed" permit to the FLM so that agency could review the AQD response to public comments. The FLM responded with a letter dated January 17, 2007 in which the FLM "confirmed the Class I analysis shows that emissions from Hugo Unit #2 alone, are not expected to cause an Adverse impact to Air Quality Related Values at CCCW" and that "the modeled increment violation at CCWA does not prohibit the state from issuing a permit for Hugo Unit #2, because the proposed unit was not shown to be a significant contributor to the modeled violation." However, the FLM reiterated their concern that the air modeling still showed an increment violation at the CCWA and expressed an interest in knowing how and when the state and EPA intend to address this violation.

The facility has demonstrated the ability to comply with all applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site, although a question on modeled exceedance of SO_2 increment at the CCWA remains. There is no active Air Quality compliance or enforcement issue concerning this facility. The Compliance and Enforcement sections of AQD concur with issuance of the permit. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Western Farmers Electric Cooperative **Permit No. 97-058-C (M-2) (PSD)**
Hugo Generating Station

The permittee is authorized to construct in conformity with the specifications submitted to the Air Quality Division (AQD) on August 29, 2005, and with supplemental information received on December 5, 2005, February 24, 2006, March 23, 2006, April 27, 2006, and November 22, 2006. The Evaluation Memorandum dated January 29, 2007, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emissions limitations for each point: [OAC 252:100-8-6(a)]

   A. EUG 1A. Coal-fired Main Boiler (HU-Unit1)

EU and Point ID#	Make	Heat Capacity (MMBtu/hr)	Serial #	Installed Date
HU-Unit1, P-1	Babcock & Wilcox	4,600	RB-575	1978

Emission Limitations

Pollutant	Limitations (lb/hr)	Limitations (TPY)
NO_X	1,672.6	4,498.85

i. Lb/hr limit is based on a 30-day rolling average, excluding startup, shutdown, and malfunction. TPY limit is based on a 12-month rolling total, excluding startup, shutdown, and malfunction. Compliance shall be demonstrated by CEMS data in accordance with 40 CFR 60.13 and 40 CFR Part 75.

ii. The limits on NO_X emissions are based on a 200 lb/hr reduction in emissions from current permitted limits. These limits shall only become effective if and when HU-Unit2 is installed and operated. Until that time, the limits on NO_X emissions for HU-Unit1, P-1 in Permit No. 97-058-TV apply.

iii. Emissions of PM, SO_2, CO, and VOC from HU-Unit1 remain limited per Specific Condition No. 1.A of Permit No. 97-058-TV.

B. EUG 1B. Supercritical Coal-fired 750 MW Boiler (HU-Unit2)

EU and Point ID#	Make	Heat Capacity (MMBtu/hr)	Serial #	Installed Date
HU-Unit2, P-24	Unknown*	7,125	Unknown*	Est. 2007

* The vendor is unknown at this time.

Emissions from HU-Unit2, P-24 shall not exceed the emissions limitations and heat input-based performance standards listed in the table below. Initial compliance with the performance standards and limitations shall be demonstrated by an initial performance stack test utilizing EPA Reference Method testing in accordance with the methods and requirements listed in Specific Condition No. 10. For emissions of SO_2, NO_X, CO (and as a surrogate for VOC), ammonia (NH_3), and mercury (Hg), continuous compliance shall be demonstrated from CEMS data in accordance with any applicable procedures of 40 CFR Part 75 and 40 CFR Part 60 Subpart Da. For emissions of PM, continuous compliance shall be demonstrated in accordance with the procedures of 40 CFR Part 60, Subpart Da. For emissions of H_2SO_4 mist, continuous compliance shall be demonstrated based on compliance with the emission limits for SO_2.

Emission Limitations and Compliance Demonstration Methods

Pollutant	Applicable Emission Limitations		
PM_{10}	**0.015 lb/MMBtu [a, c]**	**0.025 lb/MMBtu [b, d]**	**780 TPY [b, e]**

a. Filterable only.
b. Total PM_{10} (filterable and condensable).
c. Compliance shall be demonstrated in accordance with the requirements of NSPS Subpart Da.
d. Compliance shall be based on RM stack test data.
e. Compliance shall be based on RM stack test data (lb/MMBtu) and total heat input, and calculated monthly as a 12-month rolling total.

SO_2	**463 lb/24-hr period [f]**	**0.065 lb/MMBtu [g]**	**2,030 TPY [h]**

f. Compliance shall be determined from CEMS data and based on a 24-hr rolling total.
g. Compliance shall be determined from CEMS data and based on a 30-day rolling average.
h. Compliance shall be determined from CEMS data and calculated monthly as a 12-month rolling total.

NO_X	**0.07 lb/MMBtu [i]**	**0.05 lb/MMBtu [j]**	**1,560 TPY [k]**

i. Compliance shall be determined from CEMS data and based on a 30-day rolling average.
j. Compliance shall be determined from CEMS data and based on a 12-month rolling average.
k. Compliance shall be determined from CEMS data and calculated monthly as a 12-month rolling total.

CO	**0.15 lb/MMBtu [l]**	**-**	**4,690 TPY [m]**

l. Compliance shall be determined from CEMS data and based on a 30-day rolling average.
m. Compliance shall be determined from CEMS data and calculated monthly as a 12-month rolling total.

Pollutant	**Applicable Emission Limitations**		
VOC	**0.0036 lb/MMBtu [n]**	**-**	**113 TPY [o]**

n. Compliance shall be determined from RM stack test data and by compliance with CO emission limits.
o. Compliance shall be based on RM stack test data (lb/MMBtu) and total heat input, and calculated monthly as a 12-month rolling total.

Mercury	**66 x 10^{-6} lb/MWh [p]**	-	**0.25 TPY [q]**

p. Compliance shall be determined from CEMS data and based on a 12-month rolling average according to the procedures of 40 CFR 60.50Da(h).
q. Compliance shall be determined from CEMS data and calculated monthly as a 12-month rolling total.

H_2SO_4 Mist	**3.7 x 10^{-3} lb/MMBtu [r]**	**-**	**116 TPY [s]**

r. Compliance shall be determined from RM stack test data and compliance with PM and SO_2 emission limits.
s. Compliance shall be based on RM stack test data (lb/MMBtu) and total heat input, and calculated annually as a calendar year total.

NH_3	**10 ppmvd [t]**	**3.0 ppmvd [u]**	**-**

t. Compliance shall be determined from monitoring system data, corrected to 5% oxygen, and based on a 30-day rolling average.
u. Compliance shall be determined from monitoring system data, corrected to 5% oxygen, and based on a 12-month rolling average.

Opacity	**20% except for one six-minute period per hour of not more than 27% opacity [v]**

v. Compliance shall be determined from COMS data.

i. The emission limits and heat-input performance standards of this permit condition shall apply at all times except during periods of startup, shutdown, maintenance, and malfunction (SSMM). In addition, for SO_2 emissions only, emissions during emergency conditions as that term is defined in 40 CFR 60.40.Da are also excluded. During periods of SSMM, the permittee shall operate HU-Unit2 and associated air pollution control equipment in accordance with good air pollution control practices to minimize emissions. The permittee shall identify and record all measures taken to mitigate emissions and all periods of SSMM.

ii. For purposes of compliance with the NO_X, CO, PM_{10}, and Hg emission limits and heat-input performance standards of this permit condition, startup begins with flame on and ends when Hugo Unit 2 is at 30% Maximum Continuous Rating (MCR) and the inlet temperature to the SCR is equal to the catalyst manufacturer's minimum recommended operating temperature. Shutdown begins when Hugo Unit 2 is at 30% MCR and the inlet temperature to the SCR is below the catalyst manufacturer's minimum recommended operating temperature. [OAC 252: 100-8-6(a)]

iii. For compliance with the heat-input performance standards of this permit condition, the heat input shall be determined based on the methods of 40 CFR Part 75, Appendix F. HU-Unit2 shall be limited to a maximum heat input of 7,125 MMBtu/hr, as a 30-day rolling average. [OAC 252: 100-8-6(a)]

iv. HU-Unit2 shall be constructed, operated, and maintained with the following technology to control emissions: [OAC 252:100-8-6(a)]

a. Good combustion control,
b. Low-NO_X burners (LNB) and overfire air (OFA),
c. Selective catalytic reduction (SCR),
d. Fabric filter, and
e. Wet flue gas desulfurization (Wet FGD).

v. HU-Unit2 is subject to the Acid Rain Program and shall comply with all applicable requirements including, but not limited to, the following:
[40 CFR Parts 72, 73, 75 and 76]

a. SO_2 allowances,
b. Monitoring as required by 40 CFR Part 75,
c. NO_X emission limitation of 0.46 lb/MMBtu by 40 CFR Part 76,
d. Reporting of quarterly emissions to the EPA,
e. Conduct Relative Accuracy Test Audits (RATA), and
f. QA/QC plan for operation and maintenance of the continuous emissions monitoring system (CEMS).

vi. For startup fuel, HU-Unit2 shall only combust No. 2 fuel oil with a maximum fuel sulfur content of 0.5 percent by weight. [OAC 252: 100-8-6(a)]

vii. HU-Unit2 is subject to the New Source Performance Standards Subpart Da and related requirements in 40 CFR 60, Subpart A - General Provisions and state emission standards. HU-Unit2 shall comply with the emission limits and applicable requirements including, but not limited to, the following: [40 CFR 60.40Da-60.52Da]

a. At all times, the permittee shall maintain and operate HU-Unit2, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions, pursuant to 40 CFR 60.11(d).
b. The permittee shall conduct an initial and annual performance test for PM emissions. The permittee shall install, calibrate, maintain, and continuously operate a bag leak detection system. As an alternative to the annual performance tests and bag leak detection system, the permittee may install, certify, maintain, and operate a CEMS to measure and record PM emissions.
[40 CFR 60.48Da (o) & (p)]
c. The permittee shall install, operate, certify, calibrate, test and maintain CEMS for opacity, SO_2, NO_X, and O_2 or CO_2 for HU-Unit2 using the applicable methods and procedures set forth and shall record the output of the systems. The monitors shall be located before the wet control equipment if needed to prevent interference from moisture in the ductwork. SO_2 shall be sampled, measured, and monitored prior to and after the wet gas scrubber. [40 CFR 60.49Da]

d. The permittee shall install, operate, certify, calibrate, test and maintain a CEMS to measure and record the concentration of mercury in the exhaust gases associated with HU-Unit2. As an alternative to the CEMS requirement, the permittee may use a sorbent trap monitoring system (as defined in 40 CFR 72.2) to monitor Hg concentration, according to procedures described in 40 CFR 75.15 and Appendix K to part 75. [40 CFR 60.49Da]

e. The permittee shall comply with the applicable reporting and recordkeeping requirements of 40 CFR 60.51a and 60.52a including, but not limited to, the following:

Notification:
- Date construction is commenced
- Actual date of startup
- Performance test dates

Reporting:
- Performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors
- 30-day rolling average for SO_2 and NO_X
- Explanation of excess emissions caused by emergency conditions
- Monthly mercury emission rate and operating hours
- 12-month rolling average mercury emission rate
- Quarterly reports of excess opacity
- Semi-annual compliance report

Recordkeeping:
- All information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations

viii. For compliance with the emissions limits for CO in Specific Condition 1.B, the permittee shall install, calibrate, operate, and maintain CEMS in accordance with the requirements of PS-4, PS-4A, PS-4B, or PS-9 of Appendix B of 40 CFR 60 and the Quality Assurance Procedures of Appendix F of 40 CFR 60. [OAC 252: 100-8-6(a)]

ix. For compliance with the emissions limits for NH_3 in Specific Condition 1.B, the permittee shall install, calibrate, operate, and maintain a monitoring system in accordance with manufacturer's recommendations. [OAC 252: 100-8-6(a)]

x. At anytime prior to the initial startup of HU-Unit2, AQD may reopen the permit and administratively amend the mercury emission limit applicable to HU-Unit2 in order to incorporate EPA's final determination of the Clean Air Mercury Rule (CAMR) upon reconsideration, or in order to apply any appropriate AQD limitations required to meet mercury allocations under the CAMR. [OAC 252: 100-8-6(a)]

xi. The HU-Unit2 stack (P-24) shall be constructed at a minimum height of 625 feet above ground and with a maximum exit diameter of 28.5 feet. [OAC 252: 100-8-6(a)]

C. EUG 3. Coal Handling Activities

EU and Point ID#	**Activities**	**PM_{10}**	
		lb/hr	**TPY**
HU-Coal1, P-3A	Rotary Car Dumper – Roof Dust Collector 1A	3.18×10^{-3}	0.01
HU-Coal1, P-3B	Rotary Car Dumper – Roof Dust Collector 1B	3.18×10^{-3}	0.01
HU-Coal1, P-3C	Rotary Car Dumper – Roof Dust Collector 1C	3.18×10^{-3}	0.01
HU-Coal1, P-3D	Rotary Car Dumper – Roof Dust Collector 1D	3.18×10^{-3}	0.01
HU-Coal1, P-3E	Rotary Car Dumper – Bottom Dust Collector 2	4.45×10^{-3}	0.02
HU-Coal2, P-4A	Transfer House - Dust Collector 3	0.07	0.31
HU-Coal2, P-4B	Coal Silo A – Roof Dust Collector 4	0.07	0.31
HU-Coal7, P-25	Coal Silo B – Roof Dust Collector 4A	0.07	0.31
HU-Coal2, P-4C	Coal Silo A – Bottom Dust Collector 5	0.11	0.48
HU-Coal7, P-26	Coal Silo B – Bottom Dust Collector 5A	0.05	0.22
HU-Coal3, P-5A	Crusher House – Dust Collector 6	0.05	0.22
HU-Coal3, P-5B	Hugo Unit 1 Coal Silos – Dust Collector 7	0.05	0.22
HU-Coal8, P-27	Hugo Unit 2 Coal Silos – Dust Collector 8	0.05	0.22
HU-Coal5, P-7A	Reclaim Hopper No. 1 – aboveground	0.06	0.26
HU-Coal5, P-7B	Reclaim Hopper No. 2 – underground	0.02	0.09
HU-Coal5, P-7C	Reclaim Hopper No. 2 – aboveground	0.06	0.26
HU-Coal5, P-7D	Reclaim Hopper No. 3 – aboveground	0.13	0.57
HU-Coal9, P-28	Chain Reclaim (drop to reclaim hopper)	0.13	0.57
HU-Coal9, P-29	Chain Reclaim (drop to conveyor R-1)	0.13	0.57

i. Compliance with the other specific conditions for EUG 3 demonstrates compliance with the lb/hr and TPY emissions limits. No testing of emissions is required.

ii. The permittee shall comply with all applicable requirments of NSPS Subpart Y including, but not limited to, the following. The owner or operator shall also comply with applicable notification and recordkeeping requirements in Subpart A regarding new and/or modified equipment:

[OAC 252:100-4 and 40 CFR 60.250 to 60.254, 40 CFR 60.7, 60.8]

a. Notification:
- Date construction is commenced
- Actual date of startup
- Performance test dates

b. Recordkeeping:
- Opacity observations
- Operating and maintenance procedures
- Maintenance records

c. Reporting:
- Performance test results

iii. Except during periods of startup, shutdown, and malfunction, opacity from each affected unit under Subpart Y shall be less than 20 percent. [40 CFR 60.252(c)]

iv. Emission units HU-Coal1, HU-Coal2, HU-Coal3, HU-Coal7, and HU-Coal8 shall vent exhausts to fabric filters or equivalent devices with a manufacturer's guaranteed outlet emission rate for PM_{10} of 0.01 gr/dscf. [OAC 252:100-8-6(a)]

v. The permittee shall conduct Method 22 visual observations of emissions from the discharges from each of the above units (either individually or as a group of closely spaced units) at least once per week. In no case shall the observation period be less than six minutes in duration. If visible emissions are observed for six minutes in duration for any observation period and such emissions are not the result of a startup, shutdown, or malfunction, then the permittee shall conduct, for the identified point(s), within 24 hours, a visual observation of emissions, in accordance with 40 CFR Part 60, Appendix A, Method 9. When discharge points are located inside a building, the visual observation(s) may be done on the building ventilation discharges or other significant discharge points. [OAC 252:100-8-6(a)(1)]

a. If a Method 9 observation exceeds 20 percent average equivalent opacity, the permittee shall conduct at least two additional Method 9 observations within the next 24-hours.
b. If more than one six-minute Method 9 observation exceeds 20 percent average equivalent opacity in any consecutive 60 minutes; or more than three six-minute Method 9 observations in any consecutive 24 hours exceeds 20 percent average equivalent opacity; or if any six-minute Method 9 observation exceeds 60 percent average equivalent opacity; the owner or operator shall comply with the provisions for excess emissions during start-up, shut-down, and malfunction of air pollution control equipment. [OAC 252:100-25]

vi. The pressure drop across each bag filter shall not exceed the highest pressure drop allowed by the manufacturer's guarantee. The permittee shall monitor and record, either manually or electronically, the pressure drop from each bag filter daily when operated. [OAC 252:100-43]

vii. These limits shall only apply if and when HU-Unit2 is installed and operated. Until that time, the limits on the existing coal handling emissions for HU-Unit1, P-1, in Permit No. 97-058-TV apply.

D. EUG 4B. Ash Handling Activities

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-Ash6, P-30	Hugo Unit 2 Fly Ash Silo Bin Vent #1	0.58	2.54
HU-Ash6, P-31	Hugo Unit 2 Fly Ash Silo Bin Vent #2	0.58	2.54
HU-Ash7, P-32	Hugo Unit 2 Fly Ash Silo Loading to Trucks	0.06	0.26
HU-Ash8, P-33	Fly Ash Storage Building – Dust Collector 1	0.58	2.54
HU-Ash8, P-34	Fly Ash Storage Building – Dust Collector 2	0.58	2.54
HU-Ash9, P-35	Fly Ash Rail Loadout	0.06	0.26
HU-Ash10, P-36	Fly Ash Rail Bin Vent #1	0.58	2.54
HU-Ash10, P-37	Fly Ash Rail Bin Vent #2	0.58	2.54

i. Compliance with the other specific conditions for EUG 4B demonstrates compliance with these emissions limits. No testing of emissions is required.

ii. All activities in EUG 4B, with the exception of HU-Ash7 and HU-Ash9, shall vent exhausts to fabric filters or equivalent devices with a manufacturer's guaranteed outlet emission rate for PM_{10} of 0.01 gr/dscf. HU-Ash7 and HU-Ash9 shall vent exhausts to fabric filters or equivalent devices with at least 90 percent control efficiency for PM_{10}. [OAC 252:100-8-6(a)]

iii. The pressure drop across each bag filter shall not exceed the highest pressure drop allowed by the manufacturer's guarantee. The permittee shall monitor and record, either manually or electronically, the pressure drop from each bag filter daily when operated. [OAC 252:100-43]

iv. The permittee shall monitor emissions from the ash handling activities in accordance with the procedures previously listed in Specific Condition No. 1.C.v.

E. EUG 5. Facility Traffic. Emissions are fugitive and no specific limits apply.

EU and Point ID#	Activities
HU-PT, P-18	Paved and unpaved roads

F. EUG 7B. Emergency Engines

Point and EU ID#	Capacity (hp)	Make/Model	Installed Date
HU-G, P-38	525	Diesel Fire Water Pump*	Est. 2007
HU-G, P-39	2,220	Emergency Diesel Generator*	Est. 2007

***** The Make/Model is unknown at this time.

i. The emergency diesel engines installed shall not be rated above the horsepower ratings specified above.

ii. P-38 and P-39 shall only combust diesel fuel oil with a sulfur content of 0.5 percent by weight or less.

iii. P-38 and P-39 shall not operate more than 52 hours per year unless due to emergency circumstances.

iv. P-38 and P-39 shall be equipped with non-resettable hour meters.

G. EUG 8. Storage Pile Activities. Emissions are fugitive and no specific limits apply.

<table>
<tr><th>EU and Point ID#</th><th>Activities</th></tr>
<tr><td rowspan="4">HU-SP1, P-40</td><td>North Active Coal Pile: Load-in</td></tr>
<tr><td>Wind Erosion</td></tr>
<tr><td>Pile Maintenance Pushed to Reclaim 2</td></tr>
<tr><td>Pile Maintenance Pushed to Reclaim 3</td></tr>
<tr><td rowspan="3">HU-SP2, P-41</td><td>South Active Coal Pile: Load-in</td></tr>
<tr><td>Wind Erosion</td></tr>
<tr><td>Pile Maintenance Pushed to Reclaim 1</td></tr>
<tr><td>HU-SP3, P-42</td><td>North Long Term Coal Storage Wind Erosion</td></tr>
<tr><td>HU-SP4, P-43</td><td>South Long Term Coal Storage Wind Erosion</td></tr>
<tr><td rowspan="4">HU-SP5, P-44</td><td>Gypsum Pile: Load-in</td></tr>
<tr><td>Truck Load-out</td></tr>
<tr><td>Wind Erosion</td></tr>
<tr><td>Pile Maintenance</td></tr>
<tr><td rowspan="3">HU-SP6, P-45</td><td>Limestone Pile: Stackout Lowering Well</td></tr>
<tr><td>Wind Erosion</td></tr>
<tr><td>Pile Maintenance</td></tr>
<tr><td rowspan="6">HU-SP7, P-46</td><td>Landfill: Load-in</td></tr>
<tr><td>Wind Erosion</td></tr>
<tr><td>Pile Maintenance (dozer)</td></tr>
<tr><td>Pile Maintenance (compactor)</td></tr>
<tr><td>Pile Maintenance (water truck)</td></tr>
<tr><td>Pile Maintenance (grader)</td></tr>
</table>

H. EUG 9. Limestone Handling Activities

EU and Point ID#	Activities
HU-LS1, P-47	Limestone Receiving Hopper
HU-LS2, P-48	Limestone Reclaim Tunnel
HU-LS3, P-49	Limestone Silo 1
HU-LS4, P-50	Limestone Silo 2

i. These emission units shall vent exhausts to fabric filters or equivalent devices with a manufacturer's guaranteed outlet emission rate for PM_{10} of 0.01 gr/dscf.
[OAC 252:100-8-6(a)]

ii. The pressure drop across each bag filter shall not exceed the highest pressure drop allowed by the manufacturer's guarantee. The permittee shall monitor and record, either manually or electronically, the pressure drop from each bag filter daily when operated. [OAC 252:100-43]

I. EUG 10. Wastewater Spray Dryer

EU and Point ID#	Capacity (MMBtu/hr)	Make/Model	Installed Date
HU-SD, P-51	20	Wastewater Spray Dryer*	Est. 2007

* The Make/Model is unknown at this time.

Emission Limitations

EU and Point ID#	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
HU-SD, P-51	2.9	13	0.7	3.1	0.03	0.1	1.0	4.4	0.2	1.0

i. The wastewater spray dryer shall be designed for a heat rate of no more than 20 MMBtu/hr, based on the higher heating value of the fuel. [OAC 252: 100-8-6(a)]

ii. The wastewater spray dryer shall be constructed with Low-NO_X burners.

iii. The wastewater spray dryer shall only combust No. 2 fuel oil with a maximum fuel sulfur content of 0.5 percent by weight. [OAC 252: 100-8-25]

iv. The permittee shall monitor the opacity of the stack exhaust in accordance with the procedures previously listed in Specific Condition No. 1.C.v.

v. Compliance with the emission limits for NO_X, CO, VOC, and PM_{10} shall be demonstrated by manufacturer's guaranteed emission factors, or AP-42 factors, and calculated annually as a calendar year total.

J. EUG 11B. Cooling Tower Unit

EU and Point ID#	Activities	PM_{10}	
		lb/hr	TPY
HU-CT2, P-54	Hugo Unit 2 Cooling Tower	9.9	43

i. Compliance with the other specific conditions for EUG 11B demonstrates compliance with these emissions limits. No testing of emissions is required.

ii. The new cooling tower shall be constructed with drift eliminators that achieve a drift efficiency of 0.0005 percent.

2. Each boiler at the facility shall have a permanent identification plate attached which shows the make, model number, and serial number. [OAC 252:100-8-6(a)]

3. Reasonable precautions shall be taken to minimize or prevent visible fugitive dust from the facility to be discharged beyond the property line in such a manner as to damage or interfere with the use of adjacent properties, or cause ambient air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. Reasonable precautions may include, but are not limited to: [OAC 252:100-29-2]

A. Use of water or chemicals on roads, stockpiles, material processing and all transfer operations as needed where possible.

B. Apply coatings or coverings to substances susceptible to becoming air-borne or wind-borne.

C. Cover or wet materials in trucks.

D. Plant and maintain vegetation coverings or windbreaks.

E. Locate stockpiles so as to provide minimum exposure to high winds and avoid open spaces near neighboring homes and businesses.

F. Proper maintenance and operation of loading equipment.

4. The following records shall be maintained on-site to verify insignificant activities. [OAC 252:100-43]

A. For stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or diesel fuel which are either used exclusively for emergency power generation or for peaking power service: operating hours per year. This condition applies to the equipment in EUG 7B (emergency diesel generator and emergency fire water pump).

B. For activities having the potential to emit no more than 5 TPY (actual) of any criteria pollutant: activity and actual emissions.

5. When monitoring shows PM_{10}, SO_2, NO_X, CO, NH_3, or Hg emissions, or opacity, in excess of limits listed in Specific Condition No. 1 of this permit, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions during start-up, shut-down, and malfunction of air pollution control equipment. Requirements include prompt notification to AQD and prompt commencement of repairs to correct the condition of excess emissions.

[OAC 252:100-9]

6. The permittee shall maintain the following records of operations. These records shall be maintained on-site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. Records may be kept in an electronic format, unless that format is not allowed by an applicable federal standard. [OAC 252:100-43]

A. For HU-Unit2, all CEMS data for emissions of PM_{10} (if applicable), SO_2, NO_X, CO, NH_3, and Hg; and COMS data for opacity.

B. Records required by 40 CFR 60, Subpart Da for opacity, PM_{10}, SO_2, NO_X, and Hg emissions.

C. Sulfur content of fuel oil (each shipment).

D. Emissions data as required by the Acid Rain Program, 40 CFR Parts 72, 73, 75, and 76.

E. RATA test results from periodic CEMS certification tests.

F. All CEMS and COMS quality assurance documentation, including quality assurance measures, calibration checks, adjustments and maintenance performed on these systems.

G. Monthly summaries of total coal unloaded (tons) and visible emissions observations for the coal handling activities and ash handling activities.

H. Hours of operation and liquid fuels usage in the emergency diesel generator and diesel fire water pump (monthly and 12-month rolling totals).

I. Hours of operation, hourly tons of coal fired, hourly heat-input rate, hourly gross MWh, and hourly net MWh of HU-Unit2 (monthly and 12-month rolling totals).

7. No later than 30 days after each anniversary date of the issuance of Permit No. 97-058-TV (April 2, 2004), the permittee shall submit to AQD, with a copy to the EPA, Region 6, a certification of compliance with the terms and conditions of this permit. The following specific information is required to be included: [OAC 252:100-8-6 (c)(5)(A) & (D)]

A. Summary of monitoring, operation and maintenance records required by this permit.

B. Summary of emissions for HU-Unit2.

C. Executive summary of quarterly CGA and RATA reports.

8. The Permit Shield (Standard Conditions, Section VI) is extended to the following requirements that have been determined to be inapplicable to this facility.

[OAC 252:100-8-6(d)(2)]

A. OAC 252:100-7 Permits for Minor Facilities

B. OAC 252:100-11 Alternative Emissions Reduction Plans and Authorizations

C. OAC 252:100-15 Motor Vehicle Pollution Control Devices

D. OAC 252:100-17 Incinerators

E. OAC 252:100-21 Particulate Matter Emissions From Wood-Waste Burning Equipment

F. OAC 252:100-23 Control of Emissions From Cotton Gins

G. OAC 252:100-24 Particulate Matter Emissions from Grain, Feed or Seed Operations

H. OAC 252:100-35 Control of Emission of Carbon Monoxide

I. OAC 252:100-39 Emission of Volatile Organic Compounds (VOCs) in Nonattainment Areas and Former Nonattainment Areas

J. OAC 252:100-47 Control of Emissions from Existing Municipal Solid Waste Landfills

9. The permittee shall conduct performance testing and submit a written report of results for EUG 3 Coal Handling Activities to demonstrate compliance with 40 CFR 60, Subpart Y.

[OAC 252:100-43, 40 CFR 60.254, and CFR Part 60.8(a)]

A. Performance testing by the permittee shall, as applicable, use the following test methods specified in 40 CFR 60.

Method 5: Determination of PM_{10} Emissions from Stationary Sources
Method 9: Visual Determination of Opacity

B. A copy of the test plan shall be provided to AQD at least 30 days prior to each test date.

C. Performance testing shall be conducted while the coal handling equipment is operating within 10 percent of the maximum operating rate.

10. Within 60 days of achieving maximum steam production rate in HU-Unit2, not to exceed 180 days from initial start-up, and at least once every 5 years thereafter (prior to the submittal of the TV renewal application), the permittee shall conduct performance testing of HU-Unit2 and submit a written report of the results to the AQD. [OAC 252:100-43 and 40 CFR Part 60.8(a)]

A. The initial performance stack test shall use the following EPA Reference Test methods specified in 40 CFR 60 or ASTM methods as specified.

i. For diluents, either CO_2 or O_2: Method 3, 3A, or 3B.

ii. For emissions of PM_{10}: Method 5B or 17 (front half/filterable) and Method 201A/202 (back half/condensable). The permittee may request an alternative method for Method 202 using the "Miniature Acid Condensation System" method (EPA/600/3-8/056, April 1984, (NTIS PB84182823)) to correct for sulfate bias from H_2SO_4 mist emissions. A testing protocol must be submitted and approved by AQD at least 60 days prior to the stack test.

iii. For emissions of SO_2: Method 6, 6A, or 6C.

iv. For emissions of NO_X: Method 7 or 7E.

v. For emissions of H_2SO_4 mist: Method 8 or the "Miniature Acid Condensation System" method cited above, if approved by AQD.

vi. For opacity: Method 9 or a certified continuous opacity measurement system (COMS).

vii. For emissions of CO: Method 10

viii. For emissions of VOC: Method 25A (modified to exclude methane and ethane) or Method 18 (if necessary)

ix. For emissions of mercury: ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (also known as the Ontario Hydro Method), or other approved EPA methods.

B. A copy of the test plan shall be provided to AQD at least 30 days prior to each test date.

C. Performance testing shall be conducted while the HU-Unit2 is operating within 10 percent of the rate at which an operating permit authorization will be sought.

D. The testing reports shall include a representative analysis of the coal being burned during testing, including sulfur content, ash content, and Hg content.

TITLE V (PART 70) PERMIT TO OPERATE / CONSTRUCT
STANDARD CONDITIONS
(December 6, 2006)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with Title V of the federal Clean Air Act (42 U.S.C. 7401, et seq.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, for revocation of the approval to operate under the terms of this permit, or for denial of an application to renew this permit. All terms and conditions (excluding state-only requirements) are enforceable by the DEQ, by EPA, and by citizens under section 304 of the Clean Air Act. This permit is valid for operations only at the specific location listed.
[40 CFR §70.6(b), OAC 252:100-8-1.3 and 8-6 (a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. [OAC 252:100-8-6 (a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from emergency conditions and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV. [OAC 252:100-8-6 (a)(3)(C)(iii)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6 (a)(3)(C)(iv)]

C. Oral notifications (fax is also acceptable) shall be made to the AQD central office as soon as the owner or operator of the facility has knowledge of such emissions but no later than 4:30 p.m. the next working day the permittee becomes aware of the exceedance. Within ten (10) working days after the immediate notice is given, the owner operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. Every written report submitted under OAC 252:100-8-6 (a)(3)(C)(iii) shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iii)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. Unless a different retention period or retention conditions are set forth by a specific term in this permit, these records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), 8-6 (c)(1), and 8-6 (c)(2)(B)]

B. Records of required monitoring shall include:

(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions as existing at the time of sampling or measurement.

[OAC 252:100-8-6 (a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. [OAC 252:100-8-6 (a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II of these standard conditions.

[OAC 252:100-8-6 (a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act.

F. Submission of quarterly or semi-annual reports required by any applicable requirement that are duplicative of the reporting required in the previous paragraph will satisfy the reporting requirements of the previous paragraph if noted on the submitted report.

G. Every report submitted under OAC 252:100-8-6 and OAC 252:100-43 shall be certified by a responsible official. [OAC 252:100-8-6 (a)(3)(C)(iv)]

H. Any owner or operator subject to the provisions of NSPS shall maintain records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility or any malfunction of the air pollution control equipment. [40 CFR 60.7 (b)]

I. Any owner or operator subject to the provisions of NSPS shall maintain a file of all measurements and other information required by the subpart recorded in a permanent file suitable for inspection. This file shall be retained for at least two years following the date of such measurements, maintenance, and records. [40 CFR 60.7 (d)]

J. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventative or corrective measures adopted. [OAC 252:100-8-6 (c)(4)]

K. All testing must be conducted by methods approved by the Division Director under the direction of qualified personnel. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality. [40 CFR §70.6(a), 40 CFR §51.212(c)(2), 40 CFR § 70.7(d), 40 CFR §70.7(e)(2), OAC 252:100-8-6 (a)(3)(A)(iv), and OAC 252:100-43]

The reporting of total particulate matter emissions as required in Part 70, PSD, OAC 252:100-19, and Emission Inventory, shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter PM_{10}. NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5). [US EPA Publication (September 1994). PM_{10} Emission Inventory Requirements - Final Report. Emission Inventory Branch: RTP, N.C.]; [Federal Register: Volume 55, Number 74, 4/17/90, pp.14246-14249. 40 CFR Part 51: Preparation, Adoption, and Submittal of State Implementation Plans; Methods for Measurement of PM_{10} Emissions from Stationary Sources]; [Letter from Thompson G. Pace, EPA OAQPS to Sean Fitzsimmons, Iowa DNR, March 31, 1994 (regarding PM_{10} Condensables)]

L. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 CFR Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-4-5 and OAC 252:100-41-15]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6 (c)(5)(A), (C)(v), and (D)]

B. The certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period; and a statement that the facility will continue to comply with all applicable requirements.
[OAC 252:100-8-6 (c)(5)(C)(i)-(iv)]

C. Any document required to be submitted in accordance with this permit shall be certified as being true, accurate, and complete by a responsible official. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete.
[OAC 252:100-8-5 (f) and OAC 252:100-8-6 (c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5 (e)(8)(B) and OAC 252:100-8-6 (c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6 (c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6 (d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6 (d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, -5-2.2, and OAC 252:100-8-6 (a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6 (a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1 (d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6 (a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6 (c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the

DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6 (a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6 (a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within 10 days after such date.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112 (G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation, reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6 (a)(7)(C) and OAC 252:100-8-7.2 (b)]

B. The DEQ will reopen and revise or revoke this permit as necessary to remedy deficiencies in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.

C. If "grandfathered" status is claimed and granted for any equipment covered by this permit, it shall only apply under the following circumstances: [OAC 252:100-5-1.1]

(1) It only applies to that specific item by serial number or some other permanent identification.
(2) Grandfathered status is lost if the item is significantly modified or if it is relocated outside the boundaries of the facility.

D. To make changes other than (1) those described in Section XVIII (Operational Flexibility), (2) administrative permit amendments, and (3) those not defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII), the permittee shall notify AQD. Such changes may require a permit modification. [OAC 252:100-8-7.2 (b)]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6 (c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

[OAC 252:100-8-6 (c)(2)]

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

SECTION XIV. EMERGENCIES

A. Any emergency and/or exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance.

[OAC 252:100-8-6 (a)(3)(C)(iii)(II)]

B. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. [OAC 252:100-8-2]

C. An emergency shall constitute an affirmative defense to an action brought for noncompliance with such technology-based emission limitation if the conditions of paragraph D below are met.

[OAC 252:100-8-6 (e)(1)]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:
[OAC 252:100-8-6 (e)(2), (a)(3)(C)(iii)(I) and (IV)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;
(4) the permittee submitted timely notice of the emergency to AQD, pursuant to the applicable regulations (i.e., for emergencies that pose an "imminent and substantial danger," within 24 hours of the time when emission limitations were exceeded due to the emergency; 4:30 p.m. the next business day for all other emergency exceedances). *See OAC 252:100-8-6(a)(3)(C)(iii)(I) and (II).* This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken; and
(5) the permittee submitted a follow up written report within 10 working days of first becoming aware of the exceedance.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6 (e)(3)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6 (a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list. [OAC 252:100-8-2]

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or federal applicable requirement applies is not trivial even if included on the trivial activities list. [OAC 252:100-8-2]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6 (a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of 7 days, or 24 hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this subsection. [OAC 252:100-8-6 (f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) No person shall cause or permit the discharge of emissions such that National Ambient Air Quality Standards (NAAQS) are exceeded on land outside the permitted facility. [OAC 252:100-3]
(2) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]
(3) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]
(4) For all emissions units not subject to an opacity limit promulgated under 40 CFR, Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for short-term

occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. [OAC 252:100-25]

(5) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(6) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(7) Volatile Organic Compound (VOC) storage tanks built after December28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(8) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances. [40 CFR 82, Subpart A]

1. Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4.
2. Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13.
3. Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B. [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156.
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158.
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161.
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166.
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158.
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Sources' Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in Oklahoma Administrative Code 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 Code of Federal Regulations (CFR) § 70.7 (h)(1). This public notice shall include notice to the public that this permit is subject to Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 CFR § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 CFR § 70.8(a) and (c).
(5) The DEQ complies with 40 CFR § 70.8 (c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 CFR § 70.8 (d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8 (a).

(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.

(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3 (a), (b), and (c), and by EPA as provided in 40 CFR § 70.7 (f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

Western Farmers Electric Cooperative
Attn: Gerald Butcher, Environmental Supervisor
P. O. Box 429
Anadarko, OK 73005

Re: Permit Application No. 97-058-C (M-2) (PSD)
Hugo Generating Station
Choctaw County, Oklahoma

Dear Mr. Butcher:

Enclosed is the permit authorizing construction of the referenced facility. Please note that this permit is issued subject to standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by March 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me at (405) 702-4200.

Sincerely,

Grover R. Campbell, P.E.
Existing Source Permit Section
AIR QUALITY DIVISION

Cc: Valliant DEQ Office

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 N. ROBINSON STREET, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit Number: 97-058-C (M-2)(PSD)

Western Farmers Electric Cooperative,

having complied with the requirements of the law, is hereby granted permission to construct Hugo Unit 2 (inclusive of a nominal 750 MW (7,125 MMBtu/hr) coal-fired boiler) at the existing Hugo Generating Station, in Choctaw County, Oklahoma,

subject to the Standard Conditions dated December 6, 2006 and Standard Conditions both attached:

In the absence of commencement of construction, this permit shall expire eighteen (18) months from the date below, except as authorized under Section VIII of the Standard Conditions.

Director, Air Quality Division | **Date**